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Review of the Impact of Production, Processing, Storage, Transmission and Distribution of Natural Gas-Based Transportation Fuels on Air Quality

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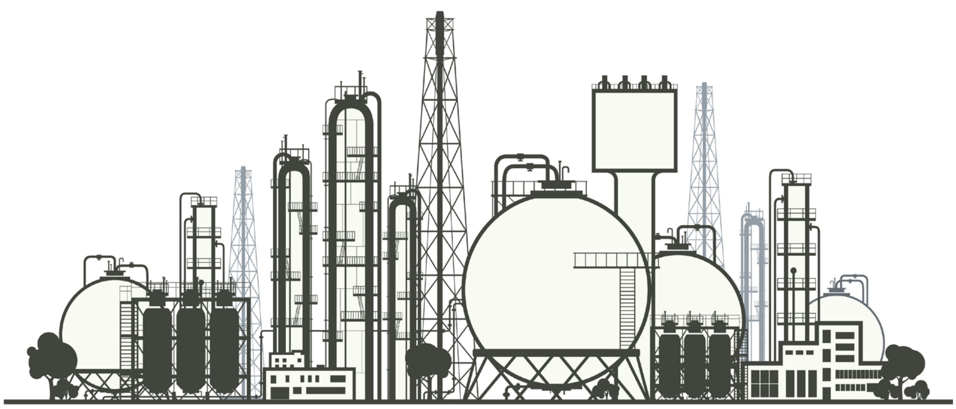

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סקירה על השפעת הפקה, עיבוד, אחסון, הולכה וחלוקה של תחליפי נפט לתחבורה מבוססי גז טבעי על זיהום אוויר

Review of the Impact of Production, Processing, Storage, Transmission and Distribution of Natural Gas-Based Transportation Fuels on Air Quality

עורכי המסמך:

פרופ' אופירה אילון
ד"ר מרים לב און
ד"ר פרי לב און
נעמה שפירא

דו"ח סופי

מוגש למדענית הראשית – המשרד להגנת הסביבה

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מדינת ישראל הולכת ומבססת את משק האנרגיה שלה על הגז הטבעי שנמצא לפני כעשור במימי הים התיכון. הגז מחליף פחם ודלק כבד להפקת חשמל, דלקים כבדים בתעשייה וכן בנזין וסולר לתחבורה. הגז הטבעי נקי יותר מדלקים פוסיליים אחרים, אולם, הוא אינו נעדר השפעות סביבתיות הן על האוויר (פליטת מזהמי אוויר קונבנציונליים וכן פליטת גזי חממה) והן על הסביבה הימית. לכן נדרש לאסדר פליטות אלה, להגביל אותן בהיתרי פליטה, לנטר ולפקח על ביצוע התקנים. האסדרה, הפיקוח והאכיפה נדרשים לא רק באסדת ההפקה, אלא לכל אורך שרשרת האספקה, לרבות, צנרת הולכת הגז וייצור תחליפי הדלקים.

מחקר זה מהווה המשך לשתי עבודות קודמות שביצע מוסד שמואל נאמן. הראשונה[1] עסקה בסקירת דרכים להערכת פליטות מתאן ממגזר הנפט והגז הטבעי ושיטות מיטביות (חישוביות ואמפיריות) לכימות, והשנייה[2] כללה סקר היתכנות לאומדן הפחת של גז טבעי בשרשרת האספקה מהבאר לרכב עבור דלקים מבוססי גז.

עבודה זו סוקרת את זיהום האוויר הנוצר לאורך שרשרת האספקה של הגז הטבעי מהבאר למיכל הדלק (Well-to-Tank – WTT), החל מהפקה והעלאת לחץ הגז לשם העברתו (מעלה הזרם, upstream), עיבוד, אחסון, הולכה וחלוקה של הגז (midstream) ועד להפקת תחליפי נפט לתחבורה מבוססי גז טבעי [חשמל או גז טבעי דחוס (גט"ד), downstream], אך אינה כוללת את הפליטות מתוצאה משימוש בכלי הרכב עצמם, המונעים בתחליפי דלק אלו (Tank-to-Wheel – TTW).

העבודה כוללת את הסוגיות הבאות: יצירת מאגר של נתונים עדכניים מהעולם וככל שיש נתונים גם מישראל, בנושא פליטות לאטמוספירה של מזהמי אוויר משרשרת ההפקה, עיבוד והובלה של גז טבעי; איסוף נתונים עדכניים על פליטות מזהמי אוויר מתהליכי הייצור של תחליפי דלקים המבוססים על גז טבעי (תוך התמקדות בייצור חשמל להנעת רכבים חשמליים - בעיקר כלי רכב פרטיים ואוטובוסים ובהפקת גט"ד להנעת משאיות, כיוון שזאת המדיניות המשתקפת מתוך מסמכים אסטרטגיים שמפרסמת ממשלת ישראל); סקירת טכנולוגיות למזעור הפליטות ולניטור והמלצות ליישום אמצעי מדיניות לצמצום השפעות סביבתיות אלו בישראל. העבודה אינה כוללת התייחסות לפליטות ממסוף הגז הנוזלי בחדרה, לפליטות מכלי שייט ומטוסים התומכים בפעילות האסדות, או לפליטות מפעילות של רכבים כבדים במסגרת מערכת הולכת הגז הטבעי, וזאת בשל העדר מידע זמין בנוגע לפעילות זאת בפרסומים ממשלתיים רשמיים.

מזהמי האוויר הקשורים במערכות של גז טבעי כוללים שורה של מזהמים אשר חלק מהם מקורם בפליטות מוקדיות ושאינן מוקדיות של הגז עצמו, וחלקם נובעים מתהליכי עיבוד, שינוע ואחסון של הגז הכוללים שימוש במנועים, מדחסים וכדומה, ואשר סוג הדלק המשמש להנעתם משפיע על פליטת המזהמים:

[1] לב-און, מ., לב-און, פ., אילון, א. , זרביב ציון, מ. (2016). הערכות גלובליות של פליטות מתאן ממתקני קידוח בים וחשיבותם חיפה, ישראל מוסד שמואל נאמן. https://www.neaman.org.il/Global-Estimates-Of-Methane-Emissions-from-Off-Shore-Drilling-Plants-and-Their-Importance

[2] אילון, א., לב-און, מ., לב-און, פ., שפירא, נ. (2020). סקר היתכנות - אומדן הפחת של גז טבעי בשרשרת האספקה מהבאר לרכב עבור דלקים מבוססי גז חיפה, ישראל מוסד שמואל נאמן. https://www.neaman.org.il/Assessment-of-Natural-Gas-Loss-from-the-Well-to-Tank-Supply-Chain-of-Natural-Gas-Based-Transportation-Fuels

- חומרים אורגניים נדיפים שאינם מתאן מקורם בגז עצמו, בקונדנסט, בשימוש בסולבנטים, בפעילות נישוב ודליפות. חומרים אלה כוללים מזהמים מסוכנים, כגון ,בנזן. בסקר שנעשה בארה"ב (1998) נמצא כי בנזן מהווה 0.1% מסך החומרים האורגניים הנדיפים שאינם מתאן. ביצוע סקר דומה בישראל, יאפשר להעריך בצורה טובה יותר את פוטנציאל הזיהום מבנזן בישראל, תרכובת מסוכנת, הידועה כחומר מסרטן ודאי בחשיפה ארוכת טווח.
- תחמוצות חנקן הנפלטות ממנועים, טורבינות ודודי חימום הנדרשים לתפעול מערכת העיבוד של הגז.
- פחמן חד חמצני הנוצר משריפה בלתי שלמה של מנועים, טורבינות ודודי חימום.
- חלקיקים הנפלטים אף הם משריפת דלקים להנעת מיכשור העיבוד של הגז וכן מתהליכים משניים.
- תחמוצות גופרית הקשורות ישירות לשיעור הגופרית בדלקים המשמשים לתהליכי העיבוד של הגז, לכל אורך שרשרת הייצור.
- אוזון, אשר הינו מזהם שניוני, הנוצר כתוצאה מתהליכים פוטוכימיים של תחמוצות החנקן והחומרים האורגניים הנדיפים.

מקטע הייצור וההולכה – ממצאי העבודה מצביעים על כך כי עיקר פליטות מזהמי האוויר נובעות מציוד, כגון, מדחסים, מנועים וכדומה. כמו כן, קיימות דליפות (מוקדיות, המתרחשות בעיקר בעת הורדת לחצים בקווים לפני פעולות תחזוקה, וכן פליטות לא מוקדיות) מהציוד ומהצנרת וכן פליטות כתוצאה מפעולות נישוף ונישוב לכל אורך שרשרת האספקה.

על מנת להעריך את הפליטות של המזהמים יש לחשב את מקדמי הפליטה שלהם. **נדבך ראשון** (Tier 1) של השיטות מתבסס על שימוש במקדמי פליטה גנריים המשמשים לחישוב פליטות על בסיס מידע על היקף הפעילות במגזר כגון סך הנפט והגז המופקים, מיובאים או מיוצאים. שיטות החישוב של פליטות **בנדבך השני** דורשות ידיעה יותר מדויקת של מקדמי פליטה המאפיינים את הפעילות הארצית, ואילו **בנדבך השלישי** נדרש ידע ממוקד של מקדמי פליטה ופעילות פרטניים בכל שלבי תפעול האתרים במקטעים השונים. במסגרת המחקר מוצגת השוואה בין הפליטות המדווחות למרשם הפליטות לסביבה (מפל"ס) לפליטות חזויות על פי מקדמי פליטה גנריים (נדבך 1). מטבע הדברים, שימוש במקדמים מקומיים, מותאמים להרכב הגז ולהרכב שאר מקורות האנרגיה בהם נעשה שימוש לכל אורך שרשרת האספקה, ומידע מדויק על הציוד בו נעשה שימוש, יאפשרו הערכות מדויקות יותר של הפליטות, ויהוו בסיס חשוב לשיפור חישובי הפליטות הן בדיווחים למפל"ס והן במצאי הפליטות הלאומי.

בישראל, על פי **נתוני המפל"ס**, סך הפליטות מאסדות תמר, ים תטיס ומרי-בי עמדו בשנת 2018 (המידע האחרון הזמין כרגע) על מעל 1,200 טונות חומרים אורגניים נדיפים שאינם מתאן, מתוכם, כ-50 טונות בנזן ואתיל בנזן, כ-63 טונות טולואן, וכ-84 טונות קסילן, ובנוסף, כ-71 טונות תחמוצות חנקן וכ-64 טונות פחמן חד חמצני. יש לציין כי באסדת תמר, התורמת העיקרית לפליטות אלה, נעשו בשנת 2019 מספר פעולות להפחתת הפליטות ומנגד, אסדת לוויתן החלה לפעול רק בשנה זו, כך שהנתונים לגבי שנת 2019 ואילך אמורים להשתנות מהותית. בנוסף, אין מידע לגבי פליטות ממסוף הגז הנוזלי (BOUY) ולא ברור מה תהיינה

הדרישות הסביבתיות מאוניות הדחיסה של הגז הטבעי שאמור להיות מיוצא מישראל. גם נתוני הפליטות של נתג"ז כלל אינם מתפרסמים.

מקטע הפקת תחליפי דלקים

- גט"ד – אין בישראל מידע זמין לגבי הפקת ותדלוק כלי רכב בגט"ד. ממצאי המחקרים לגבי רכבי גט"ד בעולם אינם עיקביים ורובם עוסקים בפליטות ממקטע השימוש ברכב (TTW), שכן הוא מהווה את החלק הארי בפליטות (אך אינו חלק ממחקר זה). ממצאים לגבי מקטע ההפקה (WTT), הכולל את מקטע הייצור וההולכה ומקטע הפקת הדלק, מתייחסים בעיקר לגזי חממה ומהם עולה כי רכבי גט"ד הינם בעלי פליטות גבוהות של גזי חממה ביחס לרכבי בנזין או דיזל. ממודל ה-GREET האמריקאי[3] ניתן ללמוד גם שרכבי גט"ד הינם בעלי פליטות גבוהות של תחמוצות חנקן, גופרית ופחמן חד חמצני בהשוואה לרכבי בנזין, אך בעלי פליטות נמוכות יחסית במזהמים חומרים אורגניים נדיפים שאינם מתאן וחלקיקים (עם זאת, המודל אינו כולל את הפליטות מתדלוק הרכבים והוא משקלל את מאפייני השוק האמריקאי בלבד).
 בשנת 2016 בוצעה סקירה בינלאומית לגבי הדרישות הסביבתיות מתחנות תדלוק[4], אולם, למיטב ידיעתנו, ממצאי המחקר טרם תורגמו לרגולציה מחייבת בישראל.
- כלי רכב המונעים בחשמל בלבד – בכלי רכב אלו אין כלל פליטות במקטע השימוש, אך הפליטות ממקטע ההפקה תלויות במידה מכרעת בתמהיל הדלקים לייצור החשמל, כמו גם הפליטות ממקטע הייצור וההולכה.

בכדי להעריך פליטות עתידיות מהנעות חלופיות השתמשנו בתחזית משרד האנרגיה לצריכת גז טבעי לתחבורה בשני תרחישים – תרחיש 'מתון' ותרחיש 'שאפתני':

- פליטות מרכבי גט"ד – חישוב הפליטות נעשה באמצעות מקדמי הפליטה של מודל ה-GREET האמריקאי (ניתוח כזה אינו יכול להחליף ניתוחי עומק שיש לבצע על נתונים אמיתיים בשוק הישראלי, כאשר אלו יהיו זמינים).
 תוספת פליטות צפויה בשנת 2030, בשני התרחישים, הינה של כ-155, 636 ו-494 טונות חומרים אורגניים נדיפים, תחמוצות חנקן ופחמן חד חמצני, בהתאמה.
- פליטות מהנעה חשמלית – כיום, רשות החשמל מפרסמת מקדמי פליטה מנורמלים ליחידת ייצור חשמל רק בעבור תחמוצות חנקן וגופרית, חסרים מקדמי פליטה למזהמים נוספים, בעיקר כאלו הנובעים מייצור חשמל בגז טבעי, כגון, חומרים אורגניים נדיפים. לצורך המחקר חושבו מקדמי פליטה המתבססים על דיווחי כל יצרני החשמל למפל"ס בשנת 2018, עם התאמה לתמהיל הדלקים העתידי הצפוי על פי רשות החשמל ומשרד האנרגיה.

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[3] https://greet.es.anl.gov/index.php?content=sampleresults

[4] וטורי, א., לוינסון, צ., דרור, ג. (2016). דרישות סביבתיות מתחנות תדלוק המשווקות תחליפי נפט לתחבורה מבוססי גז טבעי בישראל, המכללה האקדמית עמק יזרעאל.
https://www.gov.il/BlobFolder/dynamiccollectorresultitem/research_0418/he/research_sviva_r0418.pdf

תוספת פליטות צפויה בשנת 2030 של חומרים אורגניים נדיפים, תחמוצות חנקן ופחמן חד חמצני, הינם: כ-6, 246 ו-115 טונות, בהתאמה, בתרחיש ה'מתון', וכ-13, 555 ו-258 טונות, בהתאמה, בתרחיש ה'שאפתני'.

המלצות

שריפת גז טבעי הינה מופחתת פליטות ביחס לשריפת דלקים פוסיליים אחרים, אך פליטות נוספות לאורך שרשרת האספקה של הגז הטבעי, לרבות הפעלת הציוד הנדרש, עשויות לצמצם את יתרונותיו הסביבתיים. מסגרת לניהול איכות האוויר צריכה לכלול אסטרטגיות משלימות שייושמו בכל שרשרת האספקה ויתייחסו לכל אורך החיים של פרויקט או מפעל, החל מתכנון, יישום, ניטור ובקרה ועד לאכיפה כולל הפעלת אמצעים לשיפור והפחתה.

ניתן לחלק את הנושאים אשר אליהם צריך להתייחס כדלהלן:

1. **מניעה וצמצום**:
   - קביעת רשימה של מזהמי אוויר מסוכנים שכל היתרי הפליטה יחוייבו לטפל בהם.
   - קביעת הנחיות רגולטוריות לצמצום פליטות בהתאם למאפיינים הייחודיים של כל מתקן ומתקן.
   - קביעת הנחיות לכל חלקי שרשרת האספקה של גז טבעי, כולל הפקה, הולכה ודחיסה, חלוקה ותדלוק.
   - יישום ההנחיות בפועל על ידי שימוש בטכנולוגיות מיטביות, כולל שימוש בתוכניות לאיתור ותיקון דליפות (LDAR).
   - קביעת חובת הכנת תוכניות מפורטות להתמודדות עם מצבי חירום, כולל נהלים להטמעתן בתוך הארגון.
2. **ניטור פליטות**: קביעת תוכניות ניטור מפורטות, כולל סוגי הציוד המנוטר, שיטות הבדיקה, תכיפות הניטור, וכיול אמצעי הניטור.
3. **דיווח על הפליטות**:
   - דיווחים מקוונים להגברת השקיפות והזמינות לציבור, וכן דיווח שנתי כולל, לרבות דיווחים בזמן אמת ובדיעבד על תקלות.
   - חובת הדיווח צריכה לחול על מתקנים בים וביבשה לכל אורך שרשרת האספקה, ומוצע לנקוט בגישה מרחיבה לצורך הגדרת 'מתקן' כדי להמנע ממצב של פטור מדיווח לאתרים נפרדים שרמת הפליטות שלהם נמצאת מתחת לסף הדיווח. חובה זו תחול גם על קווי ההולכה של נתג"ז.
   - בנוסף על דיווחי חובה, קיימות אפשרויות גם לדיווחים וולונטריים, מעבר לנדרש על פי חוק.
4. **מעקב ובקרה**:
   - הגשת דו"חות תקופתיים לרגולטור לצורך בדיקת העמידה בתנאי היתר הפליטה.

- הגשת דיווחים נוספים בגין כל פעילות של השבתה, התנעה או תחזוקה אשר גורמת לפליטות עודפות והצעדים שננקטים בכדי להפחיתן.
- אכיפת היישום התקין באופן נחוש על ידי הרגולטור ופרסום כל פעילויות האכיפה שבוצעו באופן שקוף לציבור. יש להבטיח שעלות אי העמידה בתנאים תהיה גבוה מעלות העמידה בהם.

המסמך להלן כולל פירוט פרקטיקות וטכנולוגיות שונות לניטור והפחתת פליטות מזהמי אוויר משרשרת האספקה של גז טבעי. יעילות הפחתת המזהם, כמו גם עלות ההפחתה (הכוללת את עלות המכשור ואת עלות התפעול והתחזוקה השוטפים) הינם ספציפיים לכל מזהם בפני עצמו (תחמוצות חנקן, חומרים אורגניים נדיפים וכדומה).

המלצות נוספות

במצב הנוכחי בישראל, קיים משבר אמון עמוק בין הציבור, חברות הגז והרגולטור בכל הקשור להתנהלות הסביבתית של משק הגז (בעיקר במעלה הזרם). ישראל, כחברה ב-OECD צריכה לשקול אסטרטגיות נוספות (מחייבות, כמו גם וולונטריות) העולות במדינות העולם על מנת לשפר את הביצועים הסביבתיים של חברות בכלל ושל חברות הגז ושרשרת האספקה בפרט, כגון:

- **חיוב דיווח לא פיננסי** – כיום, הסקטור היחיד בישראל שמחויב בדיווח לא פיננסי (סביבתי וחברתי) הוא סקטור הבנקים. גילוי נאות של ההיבטים הלא פיננסיים מסייע לקובעי המדיניות, לרגולטור, למשקיעים, לצרכנים ולציבור הרחב להעריך ביצועים אלה ולגרום, למעשה, לחברות לפתח גישה אחראית. הוראה 2014/95 של האיחוד האירופי קובעת כללי גילוי של מידע לא פיננסי הנדרש מחברות גדולות, והדירקטיבה הינה מחייבת משנת 2018.
- **תוכניות סביבתיות מרצון** – ניתן לספק תמריצים והכרה לחברות המייצרות תועלות ציבוריות סביבתיות. האתגרים העיקריים העומדים בפני תוכניות וולונטריות כאלה כוללים זיהוי הדרכים לספק מוטיבציה ומשאבים לקידום יוזמות מרצון, הקמת מערך תמריצים לשם הפיכת תוכניות אלו לאטרקטיביות והקמת מנגנוני פיקוח ואכיפה ברורים ומוגדרים על מנת לוודא שהמשתתפים מצייתים לחובות ואינם "תופסים טרמפ" או מתיירקקים. חשוב להכיר ולסייע לחברות אשר פועלות "מעבר לציות".

ABSTRACT & SUMMARY (ENGLISH)

As Israel attempts to diversify its energy sources, its use of natural gas is rapidly expanding, taking advantage of discovered resources off Israel's shores in the Eastern Mediterranean. Due to expansion of offshore operations and broader introduction of natural gas into the Israeli economy, emissions of associated air pollutants along with other potential environmental and public health impacts, are coming under increasing scrutiny.

The research goals include:

- Assembly of the most recent information;
- Assessment of air pollutants emissions from the Well-to-Tank (WTT) segments of the natural gas supply chain;
- Estimation of air pollutants emissions from select natural gas-based transportation fuels;
- Compilation of technology options and policy measures for controlling emissions.

The study is organized in five chapters, including (1) Introduction, (2) Atmospheric Emissions from the Natural Gas Supply Chain, (3) Estimation of Emissions from the Natural Gas Sector in Israel, (4) Emissions Management and Control, and (5) Conclusions and Recommendations for Implementation in Israel. The study's overarching goal is to provide an indication of the potential air quality impact of producing natural gas and converting it to transportation fuels associated with compressed natural gas (CNG) or electricity used for charging electric vehicles.

Although natural gas sources contribute to emissions of Greenhouse Gas (GHG) the emphasis here is on local air pollutants (NMVOC, NOx, CO) which are precursors to the formation of ground level ozone and include air toxics (benzene, ethylbenzene, toluene, xylenes and more) that are part of the NMVOC fraction.

For CNG-fueled vehicles the emissions associated with vehicle use (Tank-to-Wheel – TTW), dominate the life cycle impacts. In the WTT segment, CNG-fueled vehicles have greater GHG, NOx, SOx and CO emissions than gasoline and lower NMVOC and PM emissions. The emissions are predominately the result of the production and processing phases, with a smaller fraction due to natural gas transmission, compression and fuel dispensing.

Although electric vehicles are virtually emission-free during operation, the incremental emissions associated with the generation of additional electricity may lead to emissions increase. Based on Ministry of Energy's projections of the additional natural gas consumptions the emissions from the fuel production segments are expected to increase for NOx, NMVOC, BTEX and Formaldehyde.

The authors recommend that an integrated approach should be applied to controlling the emissions from the natural gas industry (upstream, transmission and downstream use) within the context of a robust air quality management system. It addresses emissions avoidance and minimization, monitoring, reporting, and compliance tracking.

A list of specific recommendations (Table 24, Chapter 5) is provided emphasizing the need to anchor requirements in regulations and permits, improve compliance tracking, enhance transparency, and provide for a more robust enforcement system.

KEYWORDS

Natural gas value chain

Air pollution

Air quality

Alternative fuels

Natural gas

PLANNING VS EXECUTION

Execution	Assignments	Month
January 2019	Air pollution from natural gas value chain operations - Literature survey	Completed
February 2019	Air pollution from natural gas value chain operations - Literature survey	Completed
March 2019	Air pollution from natural gas value chain operations - Literature survey	Completed
April 2019	Air pollution from natural gas conversion to fuel - Literature survey	Completed
May 2019	Air pollution from natural gas conversion to fuel - Literature survey	Completed
June 2019	Integration of natural gas-based fuels pathways analysis	Completed
July 2019	Integration of natural gas-based fuels pathways analysis	Completed
August 2019	Integration of natural gas-based fuels pathways analysis	Completed
September 2019	Air pollution control technologies and policy measures – Review	Completed
October 2019	Air pollution control technologies and policy measures – Review	Completed
November 2019	Assembling data, calculations and writing final report	Completed
December 2019	Assembling data, calculations and writing final report	Completed
January 2020	Writing final report	Completed
February 2020	Writing final report	Completed
March 2020	Draft final report including policy measures – Internal review	Completed
April-May 2020	Final draft of report submitted to MOEP	Completed

ACRONYMS

BAT - Best Available Techniques

BCM - Billion Cubic Meters

BOEM - The U.S. Bureau of Ocean Energy Management

BREF - Best Available Techniques reference document

BTEX - Benzene, Toluene, Ethylbenzene, and Xylenes

Btu - British Thermal Units

CH_4 - Methane

CNG - Compressed Natural Gas

CO - Carbon Monoxide

CO_2 - Carbon Dioxide

EF - Emission Factor

EPA - U.S. Environmental Protection Agency

GHG - Greenhouse Gas

GOM - Gulf of Mexico

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

GTL - Gas-to-Liquids

HAP - Hazardous Air Pollutant

IEA - International Energy Agency

IEC - Israel Electric Corporation

IL-PRTR - Israel Pollutant Release and Transfer Register

INGL - Israel Natural Gas Lines

IOGP - The International Association of Oil and Gas Producers

IPCC - Intergovernmental Panel on Climate Change

kWh - Kilowatt-hour

LCA - Life Cycle Analysis

LDAR - Leak Detection and Repair

LNG - Liquefied Natural Gas

MCM - Million Cubic Meters

MEG - Monoethylene Glycol

MMBtu - Million Btu

MOE - Israel Ministry of Energy

MOEP - Israel Ministry of Environmental Protection

MW - Megawatts

NGV - Natural Gas Vehicle

NH_3 - Ammonia

NMVOC - Non-Methane Volatile Organic Compounds

NOx - Nitrogen Oxides

N_2O - Nitrous Oxide

OCS - U.S. Outer Continental Shelf

OECD - Organization for Economic Co-operation and Development

OGI - Optical Gas Imaging

O_3 - Ozone

PM - Particulate Matter

PPB - Parts Per Billion

PPM - Parts Per Million

PTW - Pump-to-Wheel

SCF / SCFD / SCFH / SCFM - Standard Cubic Feet / per Day / Hour / Minute

SO_2 / SOx - Sulfur Dioxide / Sulfur Oxides

SSM - Startup, Shutdown and Malfunction

TEG - Triethylene Glycol

Tpy - Tons per Year

TTW - Tank-to-Wheel

VOC - Volatile organic compounds

VRU - Vapor Recovery Unit

WTP - Well-to-Pump

WTT - Well-to-Tank

WTW - Well-to-Wheel

1 INTRODUCTION

In 2018, global natural gas production hit a new record of 3,937 BCM. This is a 4% (+152 BCM) increase compared to 2017 production. This trend has been observed since the financial crisis of 2008, with global production of annual gas increasing at an annually compounded growth rate of 2.8% since 2009.

The data most frequently quoted is that of natural gas production. Nonetheless it is important to note that the natural gas sector consists of three primary segments of interlinked operations that enable the delivery of produced natural gas to market:

- **Upstream** actions are comprised of exploration (including drilling) and production operations to recover the natural gas. they also include the preliminary treatment (e.g. dehydration) of raw ('wet') natural gas and its gathering and boosting (compression) operations;
- **Midstream** actions entail processing (physical separation of minor constituents), followed by transmission and storage of 'dry' natural gas as part of the steps of bringing the gas to market;
- **Downstream actions** refer to any additional processing that results in physical or chemical changes of the natural gas to produce diverse fuels and the distribution of such fuels to the end consumers.

Figure 1 depicts the 2017 global natural gas production as compiled by the International Energy Agency (IEA).

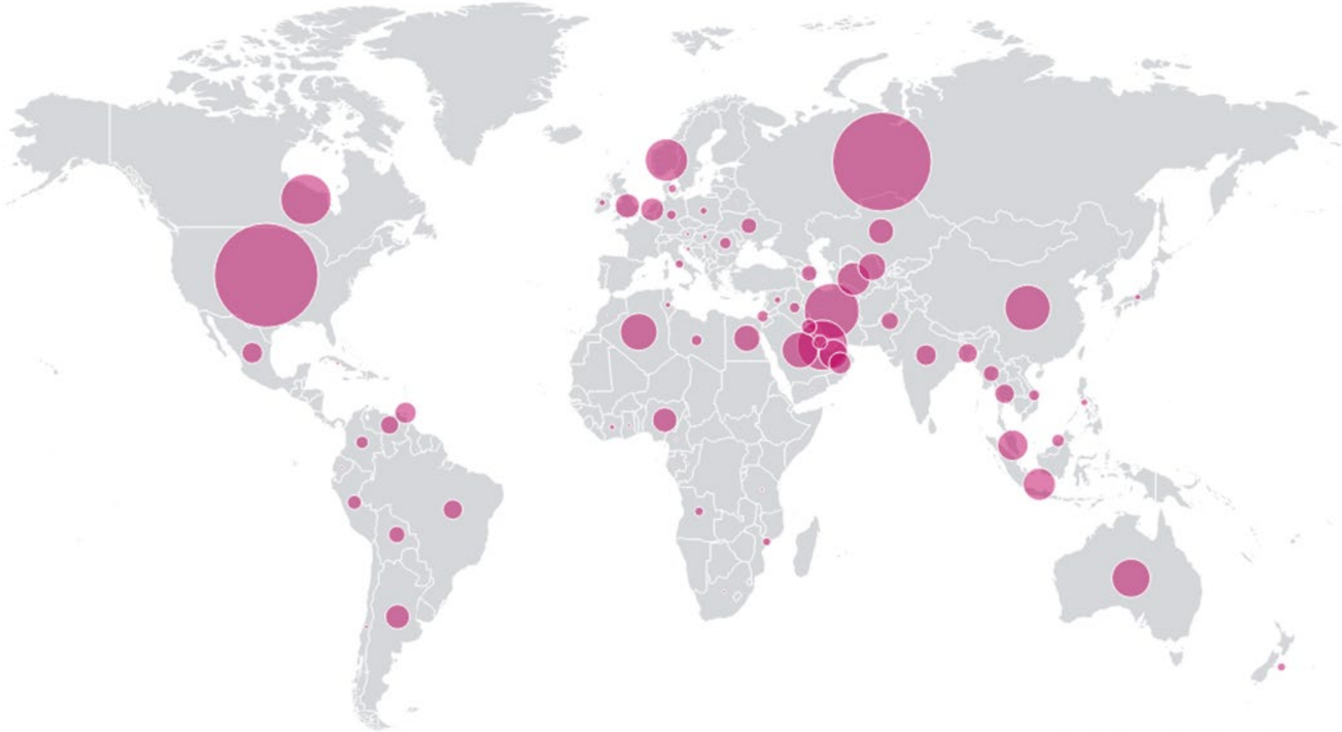

Figure 1: Global natural gas production (million tonnes of oil equivalent) in 2017[5]

Replacing coal or liquid fossil fuels for electricity and transportation with natural gas leads to reduced generation of local air pollutants such as Non-Methane Volatile Organic Compounds (NMVOC), Nitrogen Oxides (NOx) and Particulate Matter (PM), Carbon Monoxide (CO) and Sulfur Dioxide (SO_2), along with reduced emissions of Greenhouse Gases (GHGs) including Carbon Dioxide (CO_2), Methane (CH_4), Nitrous Oxide (N_2O) and more.

Air emissions associated with natural gas systems are shown in Table 1

Table 1: Pollutant sources from natural gas systems operations[6]

Pollutant	Sources
NMVOCs	Volatile organic (contain carbon) compounds that are emitted from fuel burning, solvents, paints, venting during production and processing and leakage from equipment components. See further details in Table 3

[5] IEA, Atlas of Energy, Accessed Dec. 18, 2019; http://energyatlas.iea.org/#!/tellmap/-1165808390/0

[6] https://www.researchgate.net/publication/324970454_Air_Pollution_Tolerance_Index_APTI_An_Important_Determinant_for_the_Development_of_Green_Space_in_and_Around_IndustrialUrban_Areas

Pollutant	Sources
NOx	Generated when Nitrogen and oxygen combine during combustion (burning) of fuels in sources such as engines, heaters, boilers, generators, turbines, flares.
PM	Directly emitted from burning liquid fuels such as diesel in engines and turbines. Also indirectly formed when gases from burning fuels react with sunlight and water vapor.
CO	The product of incomplete combustion in devices such as engines, heaters, generators, turbines and flares
SO_2	Produced by chemical interactions between sulfur (S) and oxygen and is directly related to the fuel S-content.

Various regulatory approaches are implemented in different countries to lower emissions from diverse sources and attain air concentrations that meet 'clean air' targets.

For example, the percent distribution of year 2017 emissions of the main air pollutants in the EU-33 by source is presented in Figure 2. The data indicate that the energy production and distribution sectors (whose major component is power generation) contribute 57.62% of the SO_2, 18.89% of the NOx, 7.15% of the NMVOCs and 3.87% of the $PM_{2.5}$ for the EU-33 region.

The general framework for regulating air pollution from stationary sources in the European Union is comprised of the requirements contained in the following directives and guidance documents[7]: Consolidated air quality directive of 2008[8];

1. National emission ceiling directive of 2016 including the requirement of annual publication of national emissions inventories[9];
2. Clean Air Policy Package to achieve compliance with existing legislation and to further reduce emissions of air pollutants until 2030;

[7] Regulation of Air Pollution: European Union, June 2018, https://www.loc.gov/law/help/air-pollution/eu.php

[8] Directive 2008/50/EC of the European Parliament and of the Council of 21 May 2008 on Ambient Air Quality and Cleaner Air for Europe (Ambient Air Quality Directive), 2008 O.J. (L 152) 1, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32008L0050&from=EN, archived at http://perma.cc/6XF2-QWC4.

[9] Directive (EU) 2016/2284 of the European Parliament and of the Council of 14 December 2016 on the Reduction of National Emissions of Certain Atmospheric Pollutants, Amending Directive 2003/35/EC and Repealing Directive 2001/81/EC (National Emissions Ceilings (NEC) Directive), art. 2, 2016 O.J. (L 344) 1, http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32016L2284&from=EN, archived at http://perma.cc/6FNN-F4PP.

3. Limits on emissions from large combustion plants (50 megawatts (MW) or more), medium combustion plants (1-50 MW) and a general framework that is based on integrated permitting, including emission limit values that must be based on the Best Available Techniques (BAT)[10,11].

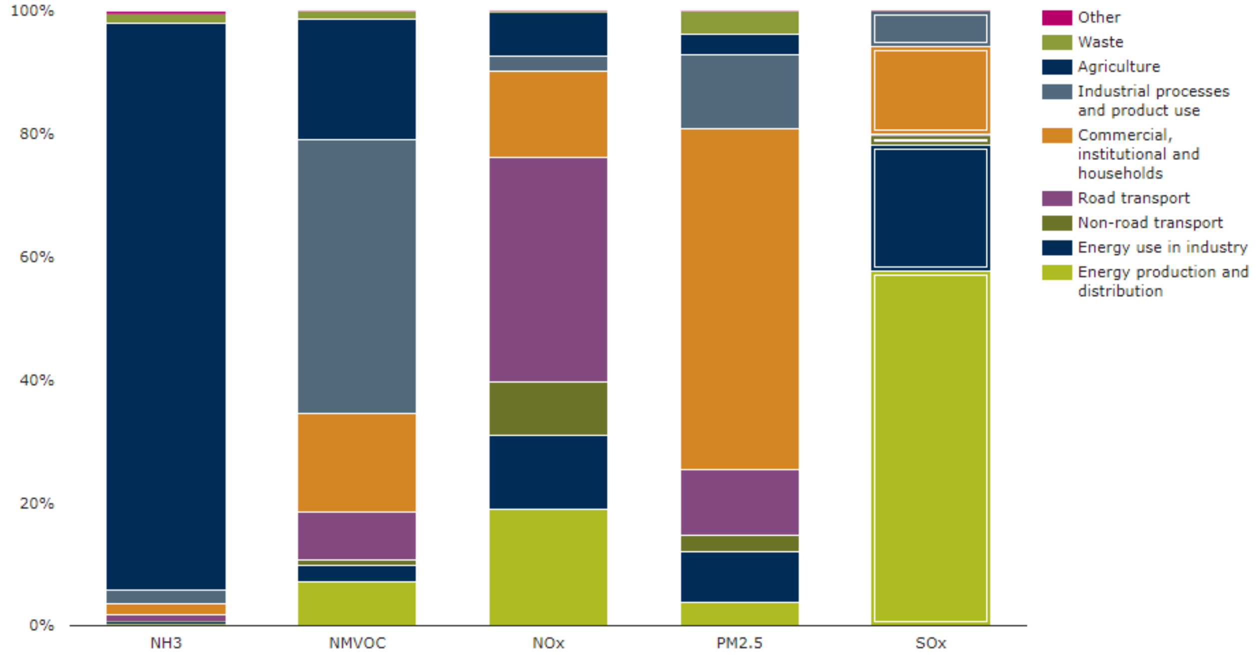

Figure 2: Percent distribution of emissions of the five main air pollutants in the EU-33 by source for 2017[12]

1.1 Key Technical Topics

This study focuses on the air pollution caused by the Well-to-Tank (WTT) supply chain of natural gas which is comprised of production, processing, storage, transmission and distribution. It also addresses emissions associated with fuel conversion and distribution operations for natural gas-based alternative fuel pathways such as Compressed Natural Gas (CNG), and electrical charging. It is

[10] Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions (integrated pollution prevention and control), ch. III & annex V, 2010 O.J. (L 334) 17, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32010L0075&from=EN, *archived at* http://perma.cc/6GA5-KUXU. See *Id*. art. 14.

[11] Reference documents under the IPPC Directive and the Industrial Emissions Directive (IED); https://eippcb.jrc.ec.europa.eu/reference/

[12] EEA 2019, Emissions of the main air pollutants in Europe, Prod-ID: IND-366-en, September 4, 2019; https://www.eea.europa.eu/data-and-maps/indicators/main-anthropogenic-air-pollutant-emissions/assessment-6

an extension and a follow-up to the previous study by these authors that addressed CH_4 and other GHG emissions from the same value chain[13].

Since natural gas supply hinges on a linked set of activities – in multiple operating segments – it is imperative to evaluate policy impacts on the entire "Natural Gas Supply Chain". Understanding the air pollution associated with supply chain operations such as field gas combustion, flaring, venting and leakage from process components is essential to planning for public health protection due to the increased use of natural gas in the Israeli economy.

The study contributes to the knowledge base by assembling the latest global information and integrating it with information that is becoming available in Israel. Such data would include relevant applications for emission permits for natural gas operations[14] in Israel and other public reporting of emissions such as the Israel Pollutant Release and Transfer Registry (IL-PRTR) data archive[15].

The integration of global data in the Israeli context keeps evolving since older studies that have shown economically viable options at the time may no longer be considered for implementation in the context of a national strategy for natural gas-based transportation fuels[16]. The results of the study will enable well informed policy decisions and provide information about control and compliance options including monitoring, reporting and verification of implementation.

1.2 Study Goals

Unlike petroleum, a significant portion of which is imported and vulnerable to external disruptions at key points in the supply chain, natural gas in Israel is derived increasingly from domestic sources and supplies are expected to rise. The study aims to contribute to a national policy assessment by investigating the potential for the natural gas supply chain – including natural gas-based transportation fuels - impacting Israeli air quality.

The specific study goals include:

1. Assemble a data base containing the most recent information on air pollution emission factors (EFs) and emission estimation from the respective sectors of natural gas production, processing, transmission, storage and distribution;

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[13] Ayalon, et al., 2018, "Assessment of Natural Gas Loss from the Well-to-Tank Supply Chain of Natural Gas-Based Transportation Fuels", Draft Final Report, Research 163-2-1, December 2018

[14] MOEP, Air permits. http://www.sviva.gov.il/subjectsEnv/SvivaAir/LicensesAndPermits/PermitEmission/Pages/default.aspx

[15] IL-PRTR. http://www.sviva.gov.il/PRTRIsrael/Pages/default.aspx

[16] Rappaport, 2013, "Report on the Environmental Impact of Constructing GTL Manufacturing Facilities", Submitted to Ministry of Environmental Protection, 30 September 2013

2. Assess emissions of air pollutants from production processes for natural gas-based fuels – CNG and electric charging of vehicles;
3. Integrate data collected and compare respective WTT emissions of targeted air pollutants from the various alternative transportation fuels pathways investigated;
4. Describe technology options and policy measures for the reduction and/or prevention of air pollutants emissions from natural gas-based fuel pathways.

2 ATMOSPHERIC EMISSIONS FROM OIL AND NATURAL GAS SUPPLY CHAINS

This chapter provides a description of direct atmospheric emissions from natural gas operations (Section 2.1) with applicable EFs for emission estimation including a discussion of the impact of emissions of pollutants that are precursors to the formation of secondary pollutants and case studies from select gas producing regions. Section 2.2 describes the atmospheric emissions from the conversion of natural gas to transportation fuels – CNG and incremental electricity for charging electric vehicles.

2.1 Atmospheric Emissions from Natural Gas Operations

Atmospheric emissions from the natural gas sector are contributed by multiple sources along its supply chain. Some of the emissions (NMVOC, CH_4) are due to venting or leakage of the natural gas itself from operating components, while other emissions (CO, CO_2, NOx. PM, and SO_2) are by-products of processing reactions or combustion. Figure 3 below depicts the natural gas operations which range from wells, gas gathering and processing facilities, storage, to transmission and distribution pipelines. All these operations are important facets of the natural gas supply chain, namely the process of getting natural gas out of the ground and conveying it to the end user.

The focus of this study is on direct emissions of non-GHG emissions from these segments, with emphasis on NMVOCs (including its air toxics constituents), NOx and PM. Emissions of CO and Sulfur Oxides (SOx) are of minor importance since they are only products of the technology employed in the combustion devices and the sulfur content or the fuel utilized and are therefore not specific just to natural gas operations. Understanding the emissions of NMVOCs and NOx is important since they are also precursors to the formation of regional ozone (O_3) and could lead to the formation of fine particulates in the atmosphere. Moreover, NMVOCs are key to assessing the impact of the natural gas sector since they are comprised of a complex mixture of volatile organic compounds (VOC) that exhibit various levels of toxicity and/or atmospheric photochemical reactivity.

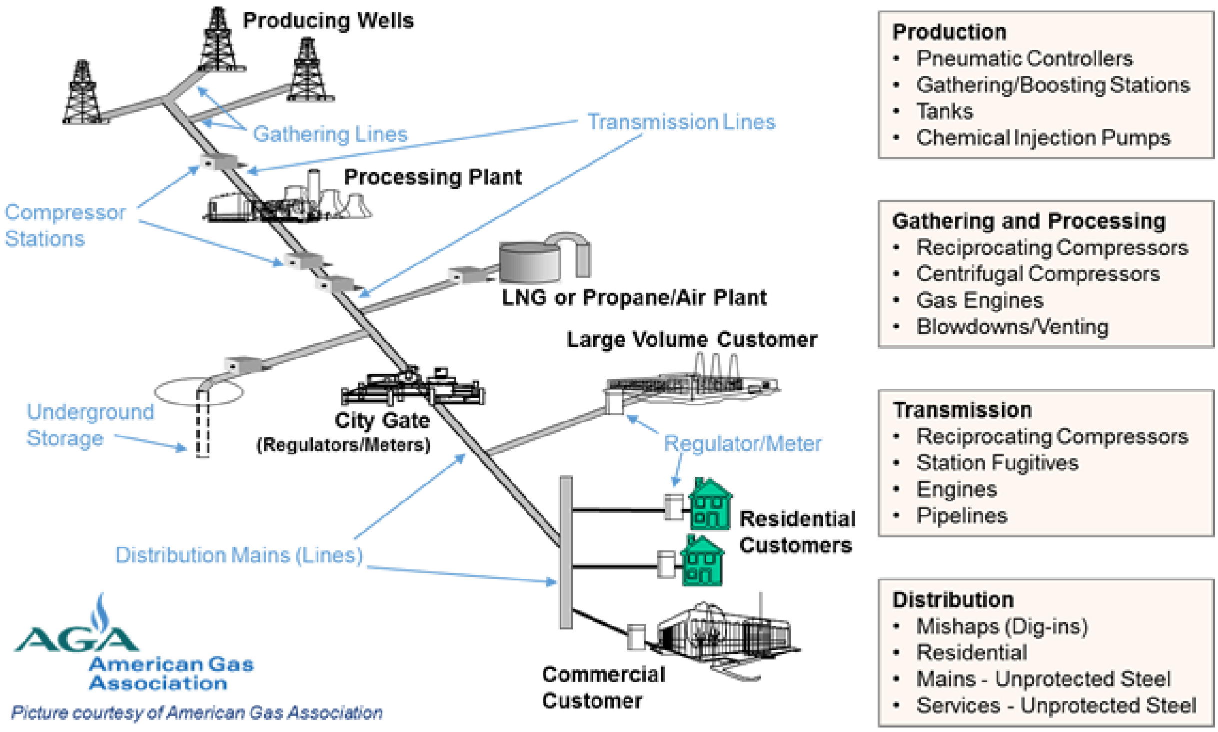

Figure 3: Schematic of the natural gas supply system chain[17]

Emission sources in the various segments of the natural gas supply chain are discussed below:

Production and Gathering – The emission sources in this segment are comprised of fugitive emissions (including leaks, venting and flaring) from the gas wellhead through to the inlet of gas processing plants, or, where processing is not required, to the tie-in points to the gas transmission systems. In the production stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves (e.g., as wellhead leaks and from well workovers), and well-site equipment such as pneumatic controllers, dehydrators and separators.

Gathering and boosting emission sources are included within the production sector. The gathering and boosting sources include gathering and boosting stations (with multiple emission sources on site, such as compressors, pneumatic controllers and tanks) and gathering pipelines. The gathering and boosting stations receive natural gas from production sites and transfer it, via gathering pipelines, to processing facilities or transmission pipelines

Gas Processing – The emission sources in this segment are comprised of fugitive emissions (including leaks, venting and flaring) from gas processing facilities. In this stage, natural gas liquids

[17] U.S. EPA Natural Gas STAR Program: Overview of the Oil and Natural Gas Industry; https://www.epa.gov/natural-gas-star-program/overview-oil-and-natural-gas-industry

and various other constituents (e.g. sulphur) from the raw gas are removed, resulting in "pipeline quality" gas, which is injected into the transmission system. Emission sources include compressors, equipment leaks, pneumatic controllers, un-combusted gas from engines and flaring, and CO_2 from flaring and sour gas removal.

Example: The Texas Commission on Environmental Quality's study of Oil & Gas platform Equipment Profile

The Texas Commission on Environmental Quality (TCEQ) is the environmental agency for the state of Texas. Within TCEQ the Office of Air is the primary authority for grants to reduce air pollution, air permitting activities, and efforts to protect and restore air quality.

Typical profiles of equipment and activity levels for oil & gas platforms were developed using platform equipment information from the Gulfwide emissions inventory that is managed by the Federal government[18]. For the Gulf of Mexico (GOM), federal waters are defined as being 10.3 miles (16 km) or greater off the Texas coast. The TCEQ study included 73 individual platforms, that are within the State of Texas jurisdiction (closer than 16 km from shore) but have equipment and emission profiles that are like the platforms in federal waters[19].

Table 2 presents the typical equipment profile for an Oil & Gas platform in Texas waters and the associated pollutants emitted by this equipment. Including, pollutants' emission from Leaks and Venting (in **Green**); and pollutants' emission from Fuel Combustion (in **Orange**).

Table 2: Air pollutants associated with typical equipment profile for a Texas Oil & Gas Platform

Equipment	CH_4	NMVOC	CO	NOx	SO_2	$PM_{2.5}$
Amine units	Green	Green			Orange	
Boilers/heaters/burners	Green	Green	Orange	Orange		Orange
Diesel engines			Orange	Orange	Orange	Orange
Drilling equipment			Orange	Orange	Orange	Orange
Combustion flares	Green	Green	Orange	Orange		Orange
Fugitive emission sources (oil & gas service)	Green	Green				
Glycol dehydrators	Green	Green	Orange	Orange		
Loading operations (condensate)	Green	Green				
Natural gas engines (2-cycle, 4-cycle lean, 4-cycle rich)	Green	Green	Orange	Orange		Orange
Natural gas turbines	Green	Green	Orange	Orange		Orange
Pneumatic pumps	Green	Green				
Pneumatic pressure/level controllers	Green	Green				
Storage tanks (condensate)		Green				
Cold vents	Green	Green				

[18] https://www.boem.gov/environment/environmental-studies/gulfwide-offshore-activity-data-system-goads

[19] TCEQ, "Offshore Oil and Gas Platform Report", ERG under TCEQ Contract No. 582-7-84003, Work Order No. 582-7-84003-FY10-25; Final Report, August 16, 2010

Typical fugitive emission sources that are common to offshore platforms as well as onshore Oil and Gas operations are:

- Connectors, Flanges, Pumps, Valves, Pressure Relief Valves, Open Ended Line, Other components (e.g. hatches, instrument meters)
- Centrifugal compressors with tandem dry seals
- Centrifugal compressors with wet seals
- Reciprocating compressors packing rods

Transmission and Storage – The emission sources in this segment are comprised of fugitive emissions (including leaks, venting and flaring) from systems used to transport processed natural gas to market (i.e., to industrial consumers and natural gas distribution systems), including natural gas storage systems. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants. Compressor station facilities are used to move the gas throughout the transmission system. Emissions sources during this process include compressors, pneumatic controllers, storage wells, leaks and venting from transmission lines, and equipment leaks from compressor stations.

Distribution – The emission sources in this segment are comprised of fugitive emissions (including leaks, venting, and any flaring) from the distribution of natural gas. Distribution pipelines take the high-pressure gas from the transmission system at “city gate” stations, reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users. Emission sources include leaks from pipelines, metering and regulating stations, meters and short-term surface storage. Short term surface storage is a man-made above-ground storage facility for storage of medium-sized quantities of natural gas. Spherical and pipe storage tanks, and other types of low-pressure containers are used for this purpose.

2.1.1 Natural gas composition

Conventional natural gas occurs in deep reservoirs that are either associated with crude oil (associated gas) or contain little or no crude oil (non-associated gas). Natural gas is a complex mixture of CH_4, CO_2, ethane, higher hydrocarbons, hydrogen sulfide (H_2S), inert gases, and trace components of many other compounds, such as aromatics like BTEX (benzene, toluene, ethylbenzene, and xylenes). The primary constituent of natural gas is CH_4 that commonly exists in mixtures with other hydrocarbons, which may be separated and sold separately for a variety of uses. The hydrocarbon content of natural gas varies by geographical location and formation type. The raw natural gas (also known as ‘wet gas’) often contains water vapor, hydrogen sulfide, CO_2, helium (He), nitrogen, and other compounds, in addition to its hydrocarbon mixture. Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produce gas that can be sold to consumers, which is also known as 'pipeline quality', or 'dry gas'.

Higher-molecular-weight hydrocarbons that exist in the reservoir as constituents of natural gas can be separated into a liquid mixture known as 'condensate'. Gas condensate can be recovered as a liquid fraction in separators, field facilities, or gas-processing plants. Typically, gas condensate is a liquid mixture of low-boiling hydrocarbons that is obtained by condensation of the hydrocarbon constituents either in the well or as the gas stream flows from the well to the treatment facility.

Gas condensate is predominately pentane (C_5H_{12}) with varying amounts of higher-boiling hydrocarbon derivatives (up to C_8H_{18}) and with relatively very little CH_4 or ethane (C_2H_6). Also, propane (C_3H_8) and butane (C_4H_{10}) may be present in condensate by dissolution in the liquids. Depending upon the source of the condensate, benzene (C_6H_6), toluene ($C_6H_5CH_3$), xylene isomers ($CH_3C_6H_4CH_3$), and ethylbenzene ($C_6H_5C_2H_5$) may also be present[20].

Therefore, natural gas composition varies from mixtures of CH_4 and C_2H_6 with very few other constituents (as in the 'dry gas' obtained after processing) to mixtures containing all the hydrocarbons (as in the raw 'wet gas'). An average general natural gas composition for 'wet' and 'dry' gas is depicted in Table 3. In order to highlight the regional nature of natural gas composition, the table also provides, for comparison, the average composition of natural gas sales from the U.S. Outer Continental Shelf (OCS) in the GOM[21]. This variability emphasizes the need for accurate composition data for each producing formation to enable accurate emissions estimation.

[20] J. G. Speight (2019), Natural Gas: A Basic Handbook, 2nd Edition, 2019. https://www.sciencedirect.com/book/9780128095706/natural-gas

[21] BOEM (2019), Year 2017 Emissions Inventory Study, OCS Study, BOEM 2019-072 (Table 4-26), October 2019.

Table 3: General and Regional composition of natural gas[22]

Constituents	General Wet Gas Composition (vol%)*	General Dry Gas Composition (vol%)*	GOM OCS Average Sales Gas Composition (vol%)*
Hydrocarbons			
CH_4	84.6	96.0	94.50
Ethane (C_2)	6.4	2.00	3.33
Propane (C_3)	5.3	0.60	0.75
Isobutane (i-C_4)	1.2	0.18	0.15
n-butane (n-C_4)	1.4	0.12	0.15
Isopentane (i-C_5)	0.4	0.14	0.05
n-Pentane (n-C_5)	0.2	0.06	0.05
Hexanes (C_6)**	0.4	0.10	0.099
Heptanes (C_7)**	0.1	0.8	0.011
Octanes and higher hydrocarbons (C_{8+})**			0.007
Non-hydrocarbons			
CO_2	<5		0.80
Helium	<0.5		
Hydrogen sulfide	<5		
Nitrogen	<10		
Argon	<0.05		
Radon, Krypton, Xenon	Traces		

Note:

* To convert from a volume basis to a mass basis for a gas stream, the standard conditions used are typically 1 atmosphere (101.325 kPa) and 15.6C. In these units: 1 g-mole = 23,685 cm^3/g-mole (23.685 m^3/kg-mole) under these conditions.

** These constituents may include straight chain hydrocarbons along with aromatic compounds such as benzene (C_6), toluene (C_7), ethylbenzene or xylene isomers (C_8).

Natural gas processing operations separate and recover natural gas liquids or other non-methane gases and liquids from a stream of produced natural gas utilizing equipment that is designed to perform one or more of the following processes: oil and condensate separation, water removal, separation of natural gas liquids, sulfur and CO_2 removal, fractionation of natural gas liquid, and

[22] S. Faramawy, T. Zaki, A.A.-E. Sakr (2016). "Natural gas origin, composition, and processing: A review", *Journal of Natural Gas Science and Engineering, 34* (2016) 34-54; http://dx.doi.org/10.1016/j.jngse.2016.06.030

other processes such as the capture of CO_2 separated from natural gas streams for delivery outside the facility.

The NMVOC fraction of natural gas is the sum-total of all the non-methane hydrocarbons in the natural gas stream. The heavier molecular weight hydrocarbons may include in addition to straight chain alkanes also traces of aromatic hydrocarbons such as BTEX. Natural gas may also contain some CO_2 and inert gases, including helium, together with hydrogen sulfide and a small quantity of organic sulfur.

2.1.2 Tier 1 NMVOC emissions estimation

Volatile organic compounds are released from fuel burning, such as gasoline or natural gas. They are also emitted from oil and gas field operations and could also be released from solvents, paints, glues, and other products that are widely used. The term is a generic name for a complex mixture of VOC, with definitions varying among countries. Each country also provides a list of compounds that are not included in the definition, primarily CH_4 or other non-reactive compounds that are exempted from regulations.

Below are a few examples of current legal definitions:

- The U.S. Clean Air Act[23] - *"Volatile organic compounds (VOC) means any compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric photochemical reactions"*.
- The European Union VOC Solvents Emissions Directive[24] - *"any organic compound having an initial boiling point less than or equal to 250 °C (482 °F) measured at a standard atmospheric pressure of 101.3 kPa."*
- Australia's National Pollutant Inventory reporting[25] - "A*ny chemical compound based on carbon chains or rings with a vapor pressure greater than 0.01 kPa at 293.15 K (i.e. 20°C), that participate in atmospheric photochemical reactions"*
- Health Canada classification[26] - *"Organic compounds that have boiling points roughly in the range of 50 to 250 °C (122 to 482 °F)"*. The emphasis is placed on commonly encountered VOCs that would influence air quality.

To indicate the universal exemption of CH_4 from the VOC list we have adopted for this study the term NMVOC.

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[23] 40 CFR § 51.100 - Definitions

[24] European Commission, The VOC Solvents Emissions Directive; https://ec.europa.eu/environment/archives/air/stationary/solvents/legislation.htm

[25] Australian Government, National Pollutant Inventory, Total VOC compounds; http://www.npi.gov.au/resource/total-volatile-organic-compounds

[26] Health Canada, Environment and Workplace Health, Section 5.2.7 Volatile Organic Compounds; http://www.hc-sc.gc.ca/ewh-semt/pubs/air/office_building-immeubles_bureaux/organic-organiques-eng.php

For a globally consistent approach to developing emission inventories we refer to the Intergovernmental Panel on Climate Change (IPCC) national guidelines for national emission inventories. The IPCC 2019 refinement to the 2006 national guidelines document provides updated EFs for all the supply chain segments of natural gas systems.

Table 4 provides an extract of Tier 1 NMVOC EFs for the respective natural gas segments which are based on average international information. Using Tier 2 and Tier 3 methods for emissions inventories is highly recommended since it will provide a better understanding of the local real-life emissions, however, it requires availability of detailed data on national activities and facilities' operations[27].

[27] Lev-On Miriam, Lev-On Perry, Ayalon Ofira, Zerbib Tsion Maayan. Global Estimates of Methane Emissions from Off-Shore Drilling Plants and Their Importance. Haifa Israel: Samuel Neaman Institute, 2016. https://www.neaman.org.il/EN/Global-Estimates-Of-Methane-Emissions-from-Off-Shore-Drilling-Plants-and-Their-Importanc

Table 4: Tier 1 emission factors for NMVOC extracted from 2019 IPCC refinement[28]

Segment	Sub segment	Emission Source	NMVOC Value	NMVOC Uncertainty	Units of Measure
Gas Production	Offshore	All	0.70	-75% to +250%	Tonnes/MCM offshore gas production
Gas Processing	Without LDAR, or with limited LDAR	All	0.15	-75% to +250%	Tonnes/MCM gas processed
			0.13	-75% to +250%	Tonnes/MCM gas produced
	Extensive LDAR	All	0.06	-75% to +250%	Tonnes/MCM gas processed
			0.05	-75% to +250%	Tonnes/MCM gas produced
	Sour gas (Acid Gas Removal)	All	0.15	-75% to +250%	Tonnes/MCM sour gas processed
Gas Transmission	Limited LDAR		0.05	-100% to +250%	Tonnes/MCM gas consumption
		All	0.06	-100% to +250%	Tonnes/kilometer pipeline
	Extensive LDAR	All	0.02	-100% to +250%	Tonnes/MCM gas consumption
			0.03	-100% to +250%	Tonnes/kilometer pipeline
Gas Storage	Limited LDAR or most activities occurring with higher- emitting technologies and practices	All	0.0094	-20% to +500%	Tonnes/MCM gas consumption
	Extensive LDAR and lower-emitting technologies and practices	All	0.0040	-20% to +500%	Tonnes/MCM gas consumption
Gas Distribution	< 50% plastic pipelines, or limited or no LDAR	All	0.041	-20% to +500%	Tonnes/MCM gas consumption
		All	0.016	-20% to +500%	Tonnes/kilometer of pipeline
	>50% plastic pipelines, and LDAR in use	All	0.009	-20% to +500%	Tonnes/MCM gas consumption
		All	0.003	-20% to +500%	Tonnes/kilometer of pipeline
	Short term surface storage	All	0.125	-70% to 140%	Tonnes/MCM of gas stored
		All	7.5E-05	-100% to 170%	Tonnes/MCM gas consumed

[28] 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Chapter 4_Volume 2 (Energy), Figure 4.2.0 (New) Key segments included in oil and natural gas systems

The EFs provided in Table 4 for gas **processing** provide calculation options that use either units of tons of emissions per MCM gas processed, or per MCM of gas produced. The volume of gas processed is thought to best reflect emissions from gas processing, and if gas processing data are available, their use is recommended. The EFs also vary with the extent of implementation of any leak detection and repair (LDAR) programs, and the use of dry seals in centrifugal compressors. As technologies and practices change over time, it is possible that one EF will be used in some years and another in other years. Where sour gas (or "acid gas") removal is occurring, the factor for that source should also be applied to the portion of gas processed with sour gas removal and added to the overall gas processing total.

For the **transmission and storage** segment several options for EFs are provided, either in units of tonnes per MCM of gas consumption, or tonnes per km of transmission pipeline. The length of transmission pipeline is thought to best reflect emissions from transmission, and if pipeline data are available, they should be applied. Where Liquefied Natural Gas (LNG) imports and exports or storage occur, the number of stations should be determined, and the EFs for LNG should be used, though no Tier 1 NMVOC EF is available for this segment.

For natural gas **distribution**, the EFs are provided both in units of tonne per MCM gas consumption, and in tonnes per km pipeline. The length of distribution pipeline is thought to best reflect emissions from distribution, and if pipeline data are available, they should be applied. The mix of pipeline materials and extent of any LDAR programs should be assessed. Where this information is unknown, or where distribution pipelines are less than 50% plastic, or where there are limited or no LDAR programs, the first set of EFs gas distribution are recommended.

2.1.3 Hazardous air pollutants from natural gas operations

Among the multiple compounds that comprise the NMVOC fraction are aromatic hydrocarbons such as BTEX. They are part of the broader category of Hazardous Air Pollutants (HAPs) or air toxics and are present in natural gas streams. The U.S. Clean Air Act defines HAPs through a list of 187 chemicals[29] and directs the U.S. Environmental Protection Agency (EPA) to devise the Maximum Achievable Control Technologies (MACT) standards, as introduced in Title III of the Clean Air Act Amendments of 1990. These standards are also known as National Emission Standards for

[29] U.S.EPA, Initial List of Hazardous Air Pollutants with Modifications; https://www.epa.gov/haps/initial-list-hazardous-air-pollutants-modifications

Hazardous Air Pollutants (NESHAP)[30], which are designed to reduce HAP emissions by industry sectors.

Emissions from various processes and operations at oil and natural gas facilities and natural gas transmission and storage facilities typically contain five different HAPs: BTEX and n-hexane. An EPA survey to locate and estimate emissions of benzene has concluded that benzene constituted, on average, approximately 0.1% by weight of NMVOC for onshore and offshore gas produced from natural gas wells and it can reach the atmosphere due to equipment leaks and other processes[31].

Example: U.S. Outer Continental Shelf Air Toxics Speciation Profile

The U.S. Bureau of Ocean Energy Management (BOEM) conducts a comprehensive survey of offshore oil and gas operations in the OCS in the GOM. The study collects activity data from all oil and gas platforms and support vessels and develops an extensive emissions inventory[32].

To estimate HAP emissions for equipment types were HAP EFs are not readily available the speciation profile shown in Table 5 was applied to independently calculated NMVOC emissions, to obtain the corresponding HAP emissions data.

This profile consists of average weight percent by pollutant obtained from a 2011 technical support document for the USEPA's oil and natural gas sector rulemaking[33]. The average weight percent shown is the percent each pollutant contributes to **total** organic compounds. To estimate HAP emissions, the NMVOC emissions estimates are multiplied by the ratio of the individual HAP average weight percent to the NMVOC average weight percent using the following equation:

$$E_{HAP} = E_{NMVOC} * \frac{WtPct_{HAP}}{WtPct_{NMVOC}}$$

Where:

E_{HAP} = HAP emissions in pounds per month
E_{NMVOC} = NMVOC emissions in pounds per month
$WtPct_{HAP}$ = Weight percent of HAP
$WtPct_{VOC}$ = Weight percent of NMVOC

[30] U.S.EPA, National Emission Standards for Hazardous Air Pollutants (NESHAP); https://www.epa.gov/stationary-sources-air-pollution/national-emission-standards-hazardous-air-pollutants-neshap-9

[31] U.S. EPA, "Locating and Estimating Air Emissions from Sources of Benzene", EPA-454/R-98-011, Pt.2, 1998

[32] BOEM (2019), Outer Continental Shelf (OCS) Study, Year 2017 Emissions Inventory Study, Bureau of Ocean Energy Management, BOEM 2019-072, October 2019; https://espis.boem.gov/final%20reports/BOEM_2019-072.pdf

[33] USEPA. (2011). Composition of natural gas for use in the oil and natural gas sector rulemaking. Memorandum from Heather P. Brown, EC/R Inc., to Bruce Moore, USEPA. July 28, 2011.

Table 5: Volatile HAP speciation profile[34]

Pollutant	Average Weight %
Benzene	0.01855
Ethylbenzene	0.00115
Hexane	0.35195
Toluene	0.0028
2,2,4 Trimethylpentane	0.0007
Xylenes	0.0048
NMVOC	17.21

HAP are part of NMVOC fraction, which is, by itself, only a fraction of total organic compounds.

Emissions from natural gas dehydration

One of the main routes for the release of BTEX to the atmosphere from oil and gas operations is when these compounds are being picked up from the processed stream in glycol dehydration and amine sweetening units[35]. In the United States HAP emissions from glycol dehydration units are regulated under 40 CFR, Part 63, Subpart HH. Glycol dehydration units processing more than 3 Million Standard Cubic Feet per Day (MMSCFD) (0.85 MCM per day) and having benzene emissions greater than 900 kg/year are required to control HAP emissions.

During gas dehydration, Triethylene Glycol (TEG) will absorb BTEX while dehydrating the gas stream during processing. The BTEX concentration from the top of the regenerator can be hundreds of times higher than that in the raw natural gas by concentrating effect of the absorption process. Natural gas dehydration by TEG differs from the use of monoethylene glycol (MEG), which is widely used in wellheads and pipelines to prevent hydrate formation at pipeline conditions[36]. When dehydrating the raw gas with TEG, the predicted absorption levels for BTEX components vary from 5-10% for benzene to 20-30% for ethylbenzene and xylene[37]. The absorption of aromatic hydrocarbons such as BTEX is favored at lower temperatures, higher pressure, increasing TEG

[34] BOEM (2019), Outer Continental Shelf (OCS) Study, Year 2017 Emissions Inventory Study, Bureau of Ocean Energy Management, BOEM 2019-072, October 2019; https://espis.boem.gov/final%20reports/BOEM_2019-072.pdf

[35] Absorption of Aromatics Compounds (BTEX) in TEG Dehydration Process. http://www.jmcampbell.com/tip-of-the-month/2011/06/absorption-of-aromatics-compounds-in-teg-dehydration-process/

[36] In offshore deep-water gas production facilities, where the exposure to lower temperatures in subsea pipelines is common, MEG is used for hydrate inhibition.

[37] Campbell, J. M. (2001). "Gas conditioning and processing, Volume 2: The Equipment Modules," John M. Campbell and Company, Norman, Oklahoma, USA, 2001.

concentration and circulation rate. When uncontrolled, the bulk of absorbed HAPs will be vented with the water vapor at the top of the regenerator.

The sources and types of air pollution from a TEG glycol dehydrator include the following[38]:

- Still Column Vent – water, CH_4, NMVOCs, BTEX, n-hexane, 2,2,4-trimethylpentane
- Flash Tank – primarily natural gas similar to fuel gas (primarily CH_4 and some NMVOC and BTEX)
- Glycol pump using high pressure natural gas – primarily natural gas like fuel gas

The most common options to mitigate NMVOC and BTEX emissions from glycol dehydrators include:

1. Condensation of the regenerator overhead vapor in a partial condenser and combustion of the remaining vapor. The uncondensed vapors are typically routed to an incinerator or, if a direct fired reboiler is used, routed to the reboiler fuel gas, or
2. Routing of the regenerator overhead vapors to another process stream in the facility. This is typically a low-pressure stream such as flash vapors from the last stage of a condensate stabilization system.

Estimation of BTEX emissions from dehydration units may rely on process simulation models or rich/lean glycol mass balance. Rich/lean glycol mass balance is a more reproducible method for emission estimations than nonconventional stack methods. Note that conventional stack methods cannot be used on the stacks of glycol dehydration units because they are too narrow in diameter and have low flow rates[39].

2.1.4 Nitrogen oxides emissions

Nitrogen oxides is the term used to describe the family of compounds that constitute of primarily nitric oxide (NO), nitrogen dioxide (NO_2), and other oxides of nitrogen. Most NOx emissions from oil and gas operations are due to combustion-related emissions sources, primarily fossil fuel combustion in heaters, engines, turbines and flares.

The mixture of compounds known as NOx is both directly emitted from industry sources and participates in a myriad of reactions that form secondary pollutants. NOx reacts with NMVOCs in

[38] Hy-BON (2014), Air Pollution and Glycol Dehydration, December 19, 2014; https://hy-bon.com/blog/air-pollution-and-glycol-dehydration/

[39] Grizzle, P.L. (1993). "Glycol Mass-Balance Method Scores High for Estimating BTEX, VOC Emissions". *Oil and Gas Journal, 91*(22):61-70, May 31, 1993

the presence of sunlight to form O_3, and one of the NOx species, NO_2, is typically controlled to minimize human exposure. Further, NOx reacts with other pollutants to form compounds that contribute to acid deposition. Finally, NOx also plays a role in several other environmental issues, including formation of particulate matter, decreased visibility, and global climate change.

In the U.S. NOx emissions data are tracked by the U.S. EPA via the National Emissions Inventory (NEI). The National Emissions Inventory is a composite of data from many different sources, including industry through the continuous emissions monitoring (CEM) program and data from numerous states, tribal, and local air quality management agencies. Different data sources use different data collection methods, and many of the emissions data are based on estimates rather than actual measurements. For major electricity generating units, most data come from CEMs that measure actual emissions. For other fuel combustion sources and industrial processes data are primarily from state, local, and tribal air quality management agencies and are estimated mostly by using EFs.

The estimated U.S. nationwide anthropogenic emissions of NOx decreased by 51% between 1990 and 2014 (from 25.2 million tons to 12.3 million tons). This downward trend results primarily from emissions reductions at electric utilities and controls that were implemented at other industrial fuel combustion sources, such as stationary engines, and on-road mobile sources.

Example: NOx Emissions from Oil and Gas Production in the North Sea[40]

North Sea production constitutes a mixture of hydrocarbons, comprising liquid petroleum and natural gas, which are produced from petroleum reservoirs beneath the sea. As of January 2015, the North Sea is the world's most active offshore drilling region with 173 drilling rigs. During the summer of 2015, a series of survey flights took place using research aircraft to assess background CH_4 (and other hydrocarbons) levels in the drilling areas. Also measured were Nitrogen Oxides (NO and NO_2), which are emitted from almost all combustion processes and are a key air pollutant, both directly and as a precursor to O_3. The oil and gas platforms in the North Sea are often manned and require significant power generation and support vessels for their continued operation, processes that potentially emit significant amounts of NOx into an otherwise relative clean environment.

During these flights the researchers measure the NOx (and any subsequently produced O_3) emitted from specific rigs as well as the NOx levels in the wider North Sea oil and gas production region. NOx mixing ratios of <10 parts per billion (ppb) were frequently observed in plumes, with significant perturbation to the wider North Sea background levels.

The main sources of NOx emissions from offshore installations are the same as for CO_2: combustion of gas and diesel in turbines and engines. The level of emissions depends both on the technology used and on fuel

[40] Lee, J. D.; Foulds, A.; Purvis, R.; Vaughan, A. R.; Carslaw, D.; Lewis, A. C. (2015), NOx Emissions from Oil and Gas Production in the North Sea, American Geophysical Union, Fall Meeting 2015, abstract id. A11M-0257, December 2015

consumption. Under the Gothenburg Protocol, Norway has undertaken to reduce its overall NOx emissions by 23% by 2020 compared with the 2005 Level. Emissions from the petroleum sector are directly regulated by means of conditions included in plans for development and operation (PDOs) and in permits under the Pollution Control Act. Figure 4 shows historical and projected emissions of NOx from the petroleum sector in Norway.

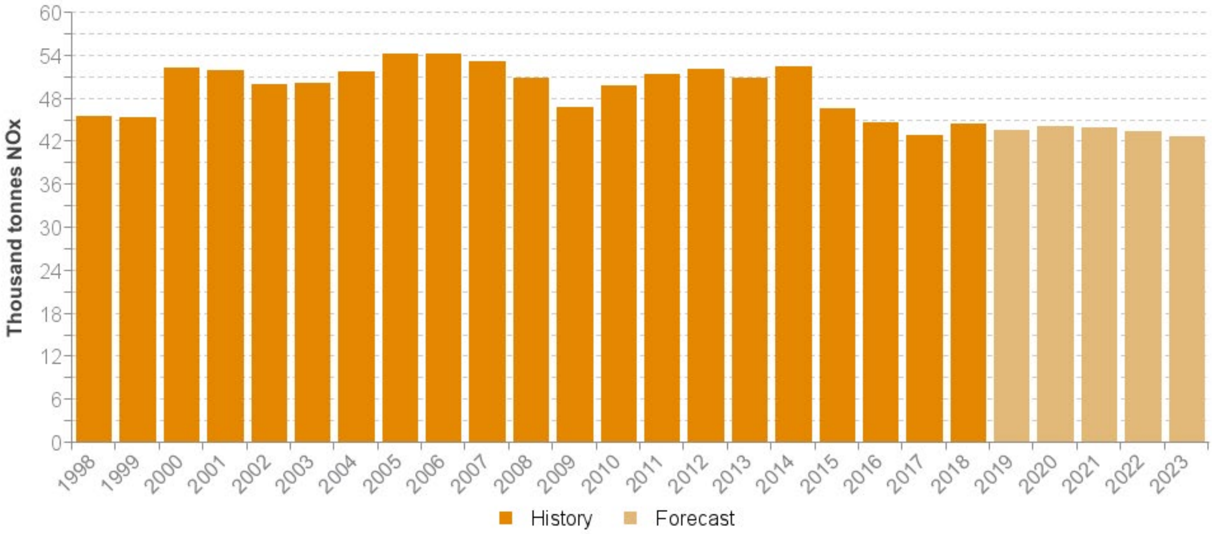

Figure 4: Historical and projected emissions of NOx from the petroleum sector in Norway[41]

2.1.5 Particulate matter emissions

Particulate matter (PM) is the general term used to describe solid particles and liquid droplets found in the air. The composition and size of these airborne particles and droplets vary. Two size ranges, known as PM_{10} and $PM_{2.5}$, are widely monitored, both at major emissions sources and in ambient air. Particles within the two size ranges behave differently in the atmosphere. $PM_{2.5}$, or fine particles, can remain airborne for long periods and travel hundreds of miles. Coarse particles, or the subset of PM_{10} (that is larger than 2.5 µm) do not remain airborne as long and their spatial impact is typically limited because they tend to deposit on the ground downwind of emissions sources. In short, as the particle size increases, the amount of time the particles remain airborne decreases.

PM can be emitted directly or formed in the atmosphere. "Primary" particles are those released directly to the atmosphere. These include dust from roads and black and/or elemental carbon from combustion sources. In general, coarse PM is composed largely of primary particles. "Secondary" particles, on the other hand, are formed in the atmosphere from chemical reactions involving

[41] Norwegian Petroleum, Emissions to Air, Updated: 14.05.2019; https://www.norskpetroleum.no/en/environment-and-technology/emissions-to-air/

primary gaseous emissions. Thus, these particles can form at locations distant from the sources that release the precursor gases. Examples include sulfates formed from SO_2 emissions from power plants and industrial facilities and nitrates formed from NOx released from power plants, mobile sources, and other combustion sources. Unlike coarse PM, a much greater portion of fine PM ($PM_{2.5}$) contains secondary particles. Secondary particles are not released directly from stacks, they are formed from precursors that contribute to formation of these secondary particles. Such precursors include NOx, SO_2, ammonia (NH_3), and other organic gases that may contribute to particle formation.

The U.S. National Emissions Inventory estimates[42] that primary PM_{10} emissions from anthropogenic sources decreased by 40% nationally between 1990 and 2014, with sources in the fuel combustion category having the largest absolute decrease in emissions (58%). Estimated primary PM $_{2.5}$ emissions from anthropogenic sources decreased 50% between 1990 and 2014, with the largest decline attributed to combustion sources.

Emissions of particulate matter and their precursors have been decreasing in the EU also, as shown in Figure 5.

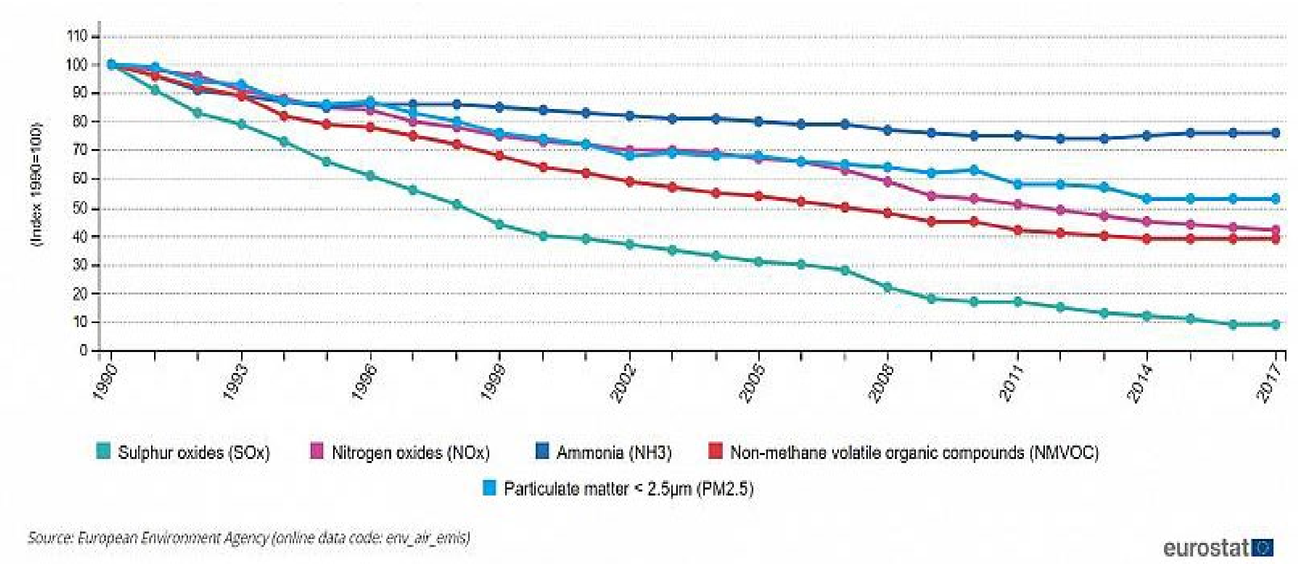

Figure 5: Emissions of air pollutants, EU-28, 1990-2017[43]

2.1.6 Ozone formation and regional air quality

Tropospheric, or ground level O_3, is not emitted directly into the atmosphere, but is driven by complex nonlinear photochemistry NOx, NMVOC and other species. It can be considered either as a

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[42] U.S. EPA (2018). 2014 National Emissions Inventory, Version 2, technical support document. https://www.epa.gov/sites/production/files/2018-07/documents/nei2014v2_tsd_05jul2018.pdf

[43] https://ec.europa.eu/eurostat/statistics-explained/index.php/Air_pollution_statistics_-_emission_inventories

"NOx-limited" or "NMVOC-limited" regime[44]. Ozone formation is aided by the reactivity of alkenes and aromatics in the atmospheric mix, which have been identified as key contributors, despite their relatively low abundance in the emissions[45].

Ozone formation in the NOx-limited and NMVOC-limited regimes mean ambient O_3 formation is controlled by the relative emissions of NOx and NMVOCs, respectively[46]. Reductions in NOx emissions from local and/or upwind sources will decrease ambient O_3 formation (and ground-level O_3 concentrations) in NOx-limited areas but increase O_3 formation in NMVOC-limited areas. On the other hand, controls of NMVOC emissions will decrease O_3 formation in areas with the NMVOC-limited regime but increase O_3 formation in NOx-limited areas. In a transition regime, both reductions in NOx and NMVOC emissions will decrease O_3 formation.

Oil- and gas-producing areas may have high levels of NMVOC and NOx that contribute to O_3 formation in the lower atmosphere, primarily due to fossil fuel use in combustion devices. Additionally, NMVOCs also evaporate, leak or are vented directly from the oil and gas being extracted, stored, and transported. Storage tanks, certain types of pumps and compressors, and leaky valves and fittings may also allow NMVOCs to escape into the atmosphere. High levels of atmospheric NMVOCs have been measured in some oil- and gas-producing areas

Emissions associated with oil and gas supply chains can have direct effects on regional air quality, though these impacts are expected to vary by region[47]. Multiple contrasting case studies illustrate the range of impacts that can occur. For example, in the U.S., emissions of NOx in the Eagle Ford Shale basin in South Texas, and in the Haynesville Shale basin in East Texas, react with relatively large emissions of biogenic hydrocarbons in the region to produce O_3 that impacts downwind metropolitan regions[48]. In contrast, emissions in the Barnett Shale basin in North Central Texas

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[44] W.P.L. Carter (1994), Development of ozone reactivity scales for volatile organic compounds, *J. Air Waste Manag. Assoc., 44* (1994), pp. 881-899; https://www.tandfonline.com/doi/abs/10.1080/1073161X.1994.10467290

[45] Carter, W.P.L., and J. H. Seinfeld. (2011). Winter ozone formation and VOC incremental reactivities in the Upper Green River Basin of Wyoming. *Atmos. Environ. 50*:255–266.

[46] S. Sillman. (1999). The relation between ozone, NO_x and hydrocarbons in urban and polluted rural environments, *Atmos. Environ., 33* (1999), pp. 1821-1845; https://www.sciencedirect.com/science/article/abs/pii/S1352231098003458

[47] D. T. Allen (2016). Emissions from oil and gas operations in the United States and their air quality implications, *Journal of the Air & Waste Management Association, 66*:6, 549-575.

[48] Pacsi, A.P., Y. Kimura, G. McGaughey, E.C. McDonald-Buller, and D.T. Allen (2015). Regional ozone impacts of increased natural gas use in the Texas power sector and development in the Eagle Ford shale. *Environ. Sci. Technol. 49*:3966–3973.

occur in a region in which the background reactivity of the atmosphere is relatively low. Direct emissions from oil and gas operations in this region produce relatively low quantities of O_3[49].

Quantifying these emissions and their effects on air quality is often complicated by variable and/or unknown background O_3 levels.

Example: Norwegian Sea Air Quality

Key findings of air quality impacts of oil & gas extraction in the Norwegian Sea[50] indicate that:

- Close to the platforms, O_3 is sensitive to NOx emissions and is much less sensitive to NMVOC emissions.
- O_3 destruction, via reaction with NO, dominates very close to the platforms.
- Far from the platforms, oil/gas facility emissions result in an average daytime O_3 enhancement of +2% at the surface.
- Larger enhancements are predicted at noon ranging from +7% at the surface to +15% at 600 meters elevation.

2.1.7 Case studies of select regions and sources

2.1.7.1 U.S. Gulf of Mexico

The U.S. national emission inventory for criteria pollutants indicates that U.S. emissions from the oil and gas sector amount to 2.77 million tons of NMVOC and 14.5 million tons of NOx[51]. These emissions account for 16% and 4.7%, respectively, of total U.S. anthropogenic emissions of these air pollutants. Notably, during the period 2002-2011, NMVOCs and NOx emissions from the oil and gas sector increased by 400% and 94%, respectively, while total U.S. anthropogenic emissions of the respective air pollutants decreased by 11% and 40% over the same period.

BOEM is required under the OCS Lands Act (OCSLA) (43 U.S.C. § 1334(a)(8)) to comply with the National Ambient Air Quality Standards (NAAQS) to ensure that OCS oil and gas exploration, development, and production sources do not significantly affect the air quality of any state.

BOEM requires since 2004 that all lease holders report their equipment count and activity levels via the Gulfwide Offshore Activities Data System (GOADS). The collected data is used to estimate Gulfwide emissions and the findings are summarized in triennial reports. The reports document operational activities and emissions of criteria pollutants and GHGs for offshore platforms and

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[49] Pacsi, A.P., N.S. Alhajeri, D. Zavala-Araiza, M.D. Webster, and D.T. Allen. (2013). Regional air quality impacts of increased natural gas production and use in Texas, *Environ. Sci. Technol. 47*:3521–3527.

[50] Tuccella, P., Thomas, J., Law, K. S., Raut, J. C., Marelle, L., Roiger, A., ... & Onishi, T. (2017). Air pollution impacts due to petroleum extraction in the Norwegian Sea during the ACCESS aircraft campaign. *Elementa: Science of the Anthropocene*, *5*, 25.

[51] David T. Allen (2016). CRITICAL REVIEW: Emissions from oil and gas operations in the United States and their air quality implications. *Journal of the Air & Waste Management Association, 66*(6), 549–575; http://dx.doi.org/10.1080/10962247.2016.1171263

support equipment in federal waters of the U.S. GOM. The Gulfwide Emissions Inventory Studies of 2014[52] and 2017[53] are the most recent reports in the sequence and they present the air pollution emissions inventory for all OCS oil and gas production-related sources on the GOM OCS, along with an inventory of all non-oil and gas production-related sources for impacts assessment modeling purposes. Pollutants covered in this inventory include:

- Criteria pollutants — CO, lead, NOx, SO_2, PM_{10}, $PM_{2.5}$
- Criteria precursor pollutants — NH_3 and NMVOCs
- GHGs — CO_2, CH_4, and N_2O
- Select HAPs and sources

The year 2014 inventory is based on data from 75 companies that reported on 1,651 active offshore platforms. For the year 2017, 57 companies reported on 1,194 active platforms and 648 inactive platforms which are not included in the emissions inventory. Table 6 presents a summary of the results from these studies of air pollutant emissions inventory for the oil and gas production sources in the GOM. The total emissions data provided in the table is the sum of emissions from all the main emission sources operating on the platforms, where the estimates adhere to EPA's emissions estimation guidelines in AP-42[54].

Clearly the emission estimates are dynamic and vary from year to year. The observed trend depends on the number of reporters and the activity levels and hours of operation for each of the platform sources. The detailed results provided by BOEM for 2014 and 2017 indicate that Cold Vents and Fugitives are the predominant sources of both CH_4 and NMVOC emissions, contributing about 65-70% of the emissions of these compounds. Combustion by Natural Gas Engines are the predominant sources of CO and NOx emissions, contributing about 70-90% of these emissions.

The average emissions values shown in Table 6 represent a straight arithmetic average of the total emissions per active platform reported for each of the air pollutants.

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[52] Wilson, D., R. Billings, R. Chang, S. Enoch, B. Do, H. Perez, and J. Sellers. (2017). Year 2014 Gulfwide Emissions inventory Study, U.S. Dept. of the Interior, Bureau of Ocean Energy Management, Gulf of Mexico OCS Region, New Orleans, LA. OCS Study BOEM 2017-044, June 2017

[53] Wilson, D., R. Billings, R. Chang, B. Do, S. Enoch, H. Perez, and J. Sellers, (2019), Year 2017 Emissions Inventory Study, U.S. Dept. of the Interior, Bureau of Ocean Energy Management, Gulf of Mexico OCS Region, OCS Study BOEM 2019-072, October 2019

[54] https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors

Table 6: U.S. offshore emissions surveys of 2014 and 2017

Emitted Compound	Total Emissions (tpy)[a] 2014	Average Emissions per Platform (tpy)[b] 2014	Total Emissions (tpy)[a] 2017	Average Emissions per Platform (tpy)[c] 2017
Criteria Pollutants				
CO	50,052	30	51,872	43
NOx	48,691	29	49,962	42
PM_{10}	668	0.4	636	1
SO_2	502	0.3	462	0
NMVOC	48,210	29	38,833	33
GHG				
CO_2	5,940,330	3,598	6,857,360	5,743
CH_4	225,667	137	187,894	157
N_2O	98	0.1	118	0.1
CO_2e	11,611,272	7,033	11,589,943	9,707

[a] tpy = tons per year, in short tons
[b] **2014** based on reporting by 75 companies for 1,651 active platforms
[c] **2017** based on reporting by 57 companies for 1,194 active platforms

2.1.7.2 Emissions from Natural Gas Engines and Turbines

Natural gas engines are widely used in all segments of the natural gas industry supply chain and are essential to running generators, pumps, compressors, and well-drilling equipment. Most of the pollutants emitted from the operations of these engines are from the exhaust, as described by the U.S. EPA in its AP-42 compilation.[55] Typical applications include compressors along pipeline routes, at storage stations and at gas processing plants. These engines are used to provide mechanical shaft power for compressors and pumps. At pipeline compressor stations, engines are used to help move natural gas from station to station. At storage facilities, they are used to help inject the natural gas into high pressure natural gas storage fields. At processing plants, these engines are used to transmit fuel within a facility and for process compression needs (e.g., refrigeration cycles).

Natural gas-fired reciprocating engines are divided into three design classes: 2-cycle (stroke) lean-burn, 4-stroke lean-burn, and 4-stroke rich-burn. Two-stroke engines complete the power cycle in a single crankshaft revolution as compared to the two crankshaft revolutions required for 4-stroke engines. All engines in these categories are spark-ignited, and are typically classified as:

[55] U.S.EPA. (2014). AP 42, Fifth Edition, Volume I Chapter 3: Stationary Internal Combustion Sources, Section 3.2 Natural Gas-fired Reciprocating Engines. Office of Air Quality Planning and Standards, RTP, North Carolina, USA. https://www3.epa.gov/ttn/chief/ap42/ch03/index.html

- **Rich-burn engines** – operate near the stoichiometric air-to-fuel ratio (16:1) with exhaust excess oxygen levels less than 4% (typically closer to 1%)
- **Lean-burn engines** – may operate up to the lean flame extinction limit, with exhaust oxygen levels of 12% or greater
- **Clean-burn engines** – are designed in accordance with a registered trademark of Cooper Energy Systems. This refers to lean-burn engines that are designed to reduce NOx by operating at high air-to-fuel ratios.

Emission estimates for these engines are based on the user knowledge of its fuel usage and the applicable EFs for each of the target compounds, as defined by the equation below:

$$E_{fu} = EF_{(kg/MMbtu)} \times H \times U \times 10^{-3}$$

Where:
E_{fu} = Emissions in Kg per month
EF = Emission factor (units are shown in parentheses)
H = Fuel heating value (Btu/scf)
U = Fuel usage (Mscf/month)

Table 7 presents EFs for criteria pollutants, air toxics, and GHGs that were extracted from AP-42 and that were used for estimating emissions from natural gas engines in the BOEM 2017 Gulfwide inventory.

Table 7: natural gas engines emission factors[56]

	2-Stroke Lean Burn EF (Kg/MMbtu)	4-stroke Lean Burn EF (Kg/MMbtu)	4-Stroke Rich Burn EF (Kg/MMbtu)	Clean Burn Engine EF (Kg/MMbtu)
Criteria Pollutants				
NMVOC	0.054	0.054	0.014	0.054
SO_2	0.0003	0.0003	0.0003	0.0003
NOx (<90% load)	0.9	0.4	1.0	0.3
CO (<90% load)	0.2	0.3	1.6	0.4
$PM_{10}/PM_{2.5}$	0.02	0.00003	0.004	0.00004
Air Toxics				
Acetaldehyde	0.004	0.004	0.001	0.002
Benzene	0.001	0.0002	0.001	0.0003
Ethylbenzene	0.00005	0.00002	0.00001	0.00002
Formaldehyde	0.03	0.02	0.009	0.02
Toluene	0.0004	0.0002	0.0003	0.0002
Xylenes	0.0001	0.0001	0.0001	0.00008
GHG				
CH_4	0.66	0.57	0.10	0.57
CO_2	49.9	49.9	49.9	49.9

Natural gas turbines are internal combustion engines that operate with rotary rather than reciprocating motion. Turbines are primarily used to power compressors and other equipment. As specified by the U.S. EPA in AP-42[57], available emissions data indicate that the turbine's operating load has a considerable effect on the resulting emission levels. Gas turbines are typically operated at high loads (equal to or greater than 80% of rated capacity) to achieve maximum thermal efficiency and peak combustor zone flame temperatures. With reduced loads (lower than 80%), or during periods of frequent load changes the combustor zone flame temperatures are expected to be lower than the high load temperatures, yielding lower thermal efficiencies and more incomplete combustion.

[56] Based on AP-42 as used in the 2017 BOEM Gulfwide Emissions Inventory (extracted from Tables 20-23)

[57] U.S.EPA. (2014). AP 42, Fifth Edition, Volume I Chapter 3: Stationary Internal Combustion Sources, Section 3.1 Stationary Gas Turbines. Office of Air Quality Planning and Standards, RTP, North Carolina, USA. https://www3.epa.gov/ttn/chief/ap42/ch03/index.html

Table 8 presents typical EFs for gas turbines operating under high load conditions. As discussed above for natural gas engines, the emission estimates for turbines are based on user-provided values of total fuel usage in conjunction with the applicable EFs, per the equation shown above.

Table 8: Emission factors for natural gas turbines[58]

Pollutant	EF (Kg/MMbtu)
Criteria Pollutants	
NMVOC	0.00095
SO_2	0.0016
NOx	0.15
$PM_{10}/PM_{2.5}$	0.0009
CO	0.04
Air Toxics	
Acetaldehyde	0.00002
Benzene	0.0000054
Ethylbenzene	0.000015
Formaldehyde	0.00032
Toluene	0.00006
Xylenes	0.00003
GHG	
CH_4	0.004
CO_2	49.9
N_2O	0.0014

2.1.7.3 The international association of oil and gas producers aggregated emission data

The International Association of Oil and Gas Producers (IOGP) presents aggregated data on exploration and production activities by member companies which are responsible for about 27% of global production sales. Variation in performance is due to several factors and include gas-oil ratio of the crude oil, reservoir and field characteristics, production techniques, age of the fields, emissions control technologies and more. The data collected can be used to compare facility performance with other companies and may act as an incentive for improvements.

[58] Based on AP-42 as used in the 2017 BOEM Gulfwide Emissions Inventory (extracted from Tables 24)

The emissions reported by the IOGP member companies in 2017, **per thousand tonnes of hydrocarbon production**, are presented in Table 9[59]:

Table 9: Emissions reported by the IOGP member companies for year 2017

	NMVOC	SO_2	NO_X	CH_4
Emissions per hydrocarbon production (tonne/1000t)	0.44	0.2	0.37	0.75
Change from 2016	+2%	+11%	+6%	-16%
Regional averages (tonne)				
Lowest	0.1 (Russia & Central Asia)	0.02 (Europe)	0.2 (Middle East)	0.1 (Middle east)
Europe	0.2	0.02	0.3	0.4
Highest	0.9 (South & Central America)	0.6 (Middle East)	0.6 (All Americas)	1.7 (North America)
Sources of emissions (where the source is specified)				
Venting or Vents	**53**%	2%	-	**53**%
Flaring	21%	**53**%	4%	17%
Fugitive losses	22%	1%	1%	22%
Energy use	4%	44%	**95**%	8%

2.2 Atmospheric Emissions from Fuel Conversion

Because the use of natural gas for transportation requires compressing, liquefying, or conversion, it is important to determine its best use as a transportation fuel. This will involve economical, safety and environmental considerations such as energy use and emissions of GHGs and other air pollutants. The next sections present some applicable literature data. It should also be noted that more thorough site-specific studies should be carried out in each location since the results are highly dependent on fuel composition, production, distribution, fueling practices and the vehicles types in the local fleet. For electric vehicles consideration it would also depend on the energy mix of electricity production.

[59] https://www.iogp.org/bookstore/product/2017e-environmental-performance-indicators-2017-data/

2.2.1 Compressed natural gas

Among all alternative fuels, CNG is considered as one of the best substitutes for gasoline and diesel fuel due to its broad availability around the world, its clean burning characteristics, and the economics of its use as a fuel in gasoline and diesel engines[60]. As of 2019 there are globally more than 27 million Natural Gas Vehicles (NGVs)[61] on the road - 71% in Asia Pacific (66% in 2016), 20% in Latin America (24% in 2016), 7% in Europe (8.6% in 2016), and about 1% in Africa and North America (1.4% in 2016)[62]. There are several dozens of passenger car, light commercial vehicles, trucks and buses models currently on the road (the majority are bi-fuel – natural gas and gasoline).

The overarching goal of Life Cycle Analysis (LCA) or Well-to-Wheel (WTW) studies for natural gas-based fuels such as CNG or LNG is to assess which mode of natural gas-based mobility offers the most compelling future environmental benefits. However, only a few extensive analyses have been conducted targeting CNG as a fuel, with often varied and even contrasting results[63] [64]. The key differences noted are due to varying fuel composition, different NGV types (dedicated, bi-fuel or dual-fuel), improper retrofitting of gasoline or diesel engines, maintenance practices, and system integration of CNG vehicles. The difference also depends on the emission standard of the vehicles to which they are compared[65].

Most of the data presented in the literature about vehicle emissions address the Tank-to-Wheel (TTW) segment (i.e., exhaust emission). Moreover, the emissions associated with vehicle use, and the on-board combustion system, dominate the life cycle impacts[66] [67]. Although the vehicle use segment is out of the scope for this study, it is worth mentioning that in developed countries, tailpipe emissions are required to meet increasingly more stringent, near zero, air pollutants

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[60] Khan, M. I., Yasmeen, T., Khan, M. I., Farooq, M., & Wakeel, M. (2016). Research progress in the development of natural gas as fuel for road vehicles: a bibliographic review (1991–2016). *Renewable and Sustainable Energy Reviews*, *66*, 702-741.

[61] NGVs' is all land-based motor vehicles, from two wheelers through to off-road. It includes original equipment manufacturers' vehicles, factory-approved conversions and post-sale conversions. Fuels include CNG, LNG and biomethane (RNG)

[62] http://www.iangv.org/current-ngv-stats/

[63] Khan, M. I., Shahrestani, M., Hayat, T., Shakoor, A., & Vahdati, M. (2019). Life cycle (well-to-wheel) energy and environmental assessment of natural gas as transportation fuel in Pakistan. *Applied energy*, *242*, 1738-1752.

[64] Khan, M. I., Yasmin, T., & Shakoor, A. (2015). International experience with compressed natural gas (CNG) as environmental friendly fuel. *Energy Systems*, *6*(4), 507-531.

[65] Khan, M. I., Yasmin, T., & Shakoor, A. (2015). Technical overview of compressed natural gas (CNG) as a transportation fuel. *Renewable and Sustainable Energy Reviews*, *51*, 785-797.

[66] Dai, Q., & Lastoskie, C. M. (2014). Life cycle assessment of natural gas-powered personal mobility options. *Energy & fuels*, *28*(9), 5988-5997.

[67] Hagos, D. A., & Ahlgren, E. O. (2018). Well-to-wheel assessment of natural gas vehicles and their fuel supply infrastructures–Perspectives on gas in transport in Denmark. *Transportation Research Part D: Transport and Environment*, *65*, 14-35.

emission limits. Hence, one advantage to NGVs is their ability to meet these stringent standards with less complicated emissions controls, though their emissions benefits are evident mainly when replacing older conventional vehicles.

On the other hand, NGVs have greater GHG emissions than diesel and gasoline in the WTT segment[68]. The GHG emissions impacting the CNG and LNG life cycle are predominately the result of production-phase fuel leakage[69] [70] (only 8% is associated with the dispensing procedure[71]). High CH_4 leakage rate could potentially offset the advantages of natural gas in transport, so most of the WTT studies focus on the GHG emissions and energy use[72]. As a result, there is almost no updated and relevant data on the impact of other air pollutants on WTT emissions from NGVs. Section 2.1 above presents the emissions from the production, transmission and distribution of natural gas, while this section presents some available data for the emissions due to the conversion of natural gas to fuel and from the fueling dispensing systems.

To achieve an acceptable vehicle driving range between refueling, it is necessary to increase the density of natural gas because CH_4 in its gaseous form has a density of 15.4 g/m^3 at standard temperature and pressure compared to gasoline, which has a density of 744,000 g/m^3. For passengers and light-duty vehicle applications, natural gas is typically carried as CNG in tanks pressurized to 3600 psi (248 bar), which brings its energy density to about 26% of that of gasoline[73]. For heavy-duty vehicle applications, cryogenically cooling natural gas to LNG at -162°c increases the density but adds substantially to the energy demand and cost.

Natural gas compression is often done at a refueling station using industrial compressors and storage tanks, although home refueling compressors have also become available for CNG Vehicles.

Figure 6 presents an illustration of a CNG fueling station, where the station has a direct connection to the gas transmission or distribution system (also called "mother station"). The station usually

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[68] https://www.concawe.eu/wp-content/uploads/2017/01/cr121-well-to-wheels-2003-01920-01-e.pdf
[69] https://afdc.energy.gov/vehicles/natural_gas_emissions.html
[70] Life cycle emissions of CNG and LNG are nearly identical.
[71] thinkstep (2017). Oliver Schuller, Benjamin Reuter, Jasmin Hengstler, Simon Whitehouse, and Lena Zeitzen "Greenhouse Gas Intensity of Natural Gas", thinkstep for NGVA, V1.1, May 5, 2017. http://www.snam.it/export/sites/snam-rp/repository/media/energy-morning/allegati_energy_morning/20170601_1.pdf
[72] For more information, see: Ayalon O., Lev-On M., Lev-On P., Shapira N. (2020). Assessment of Natural Gas Loss from the Well-to-Tank Supply Chain of Natural Gas-Based Transportation Fuels. Haifa Israel: Samuel Neaman Institute. https://www.neaman.org.il/en/Assessment-of-Natural-Gas-Loss-from-the-Well-to-Tank-Supply-Chain-of-Natural-Gas-Based-Transportation-Fuels
[73] 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).

includes a compressor and storage vessels and may also include a dryer (if moisture removing is required) and metering equipment at the entrance to the station (utility gas meter), and on the dispensing device.

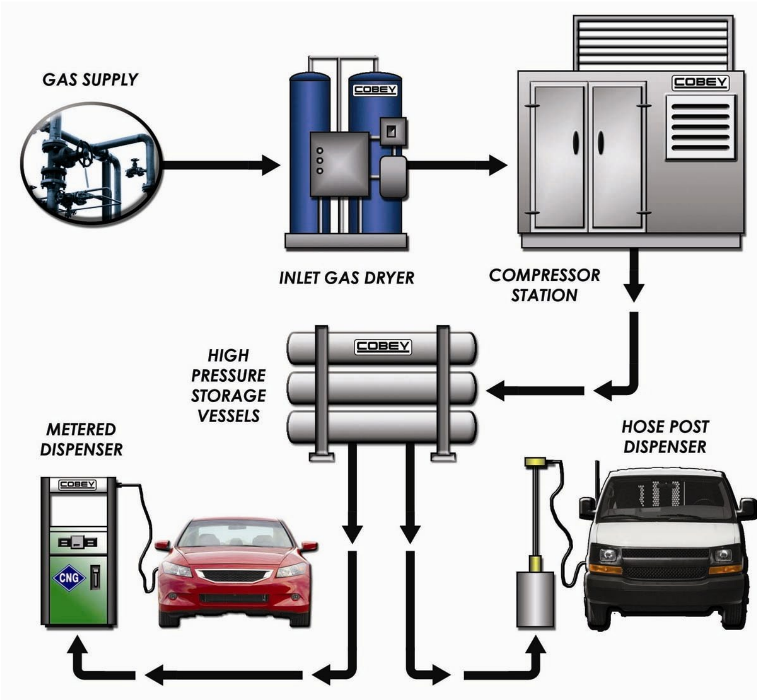

Figure 6: Illustration of CNG Fueling Stations[74]

Natural gas transmitted by pipelines may contain some light hydrocarbons and some inert compounds since its composition vary between producing formations and regions. The differences in composition may result in a range of volumetric heating values leading to significant differences in combustion characteristics as measured by the CH_4 content or octane number[75].

The compressor is the main source for potential combustion emissions, especially if it is powered by diesel. The key assumptions about industrial and electrically powered compressors are that they have high efficiencies in the range of 91.7% and 97.9% with an average of 93.1%[76], and 96.6%[77], respectively.

[74] https://cngtimes.wordpress.com/tag/fueling-stations/

[75] 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.

[76] Curran, S. J., Wagner, R. M., Graves, R. L., Keller, M., & Green Jr, J. B. (2014). Well-to-wheel analysis of direct and indirect use of natural gas in passenger vehicles. *Energy*, *75*, 194-203.

[77] Ally, J., & Pryor,T. (2007). Life-cycle assessment of diesel, natural gas and hydrogen fuel cell bus transportation systems. *Journal of Power Sources,170*(2),401-411.

The fueling dispenser works in a closed system, unlike a gasoline dispenser, so the emissions potential is relatively low. The refueling process can be conducted as a fast fill, with refueling time similar to gasoline refueling, or as a time fill (overnight fill). When there is no direct connection to the gas grid a "daughter station" model is used – in this case the dispensing can be done through a mobile cascade (a CNG tanker) or when the fueling station is fed by a natural gas tanker while the compressing is performed on-site.

A study which compares ambient BTEX concentrations in refueling stations in Iran, suggests that BTEX concentrations in gasoline stations were slightly, but not significantly, higher than those in CNG stations[78], as presented in Table 10. This might be due to more strict safety regulations applied for CNG refueling stations as well as the fact that BTEX compounds were present at very low concentrations in the CNG fuel utilized.

Table 10: Average concentrations of BTEX compounds per fuel

	Benzene (mg/m^3)	Toluene (mg/m^3)	Xylene (mg/m^3)	Ethylbenzene (mg/m^3)
Gasoline Stations	2.13	1.84	1.66	2.79
CNG Stations	1.83	1.74	1.63	2.6

Lower or higher concentrations might be due to differences in the NMVOC contents of the fuel (depending on the fuel origin and on national regulations limiting specific constituents of the fuel), fuel vapor control systems applied in refueling stations or different refueling methods and the throughput volume in the refueling station.

The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model[79] is designed to perform LCA simulations of alternative transportation fuels and vehicle technologies. The analysis includes the amount of air pollutant emissions for both Well-to-Pump (WTP)[80] and Pump-to-Wheel (PTW) for different fuels. Table 11 provides data on emissions per unit of energy from passenger car fueled by CNG and gasoline – both based on US average fuel mix.

[78] Hazrati, S., Rostami, R., Fazlzadeh, M., & Pourfarzi, F. (2016). Benzene, toluene, ethylbenzene and xylene concentrations in atmospheric ambient air of gasoline and CNG refueling stations. *Air Quality, Atmosphere & Health*, *9*(4), 403-409.

[79] https://greet.es.anl.gov/index.php?content=sampleresults

[80] Well-to-Pump is similar to Well-to-Tank but does not include the emissions associated with dispensing the fuel into the consumer vehicles – it stops at the stage of delivering the fuels at the stations.

Table 11: WTW emissions from GREET model, for CNG and gasoline

Pollutant	CNG WTP (g/mmBtu)	CNG PTW (g/mmBtu)	CNG TOTAL (g/mmBtu)	Gasoline WTP (g/mmBtu)	Gasoline PTW (g/mmBtu)	Gasoline TOTAL (g/mmBtu)
CO	35	600	635	15	630	645
NOx	45	27	72	30	28	58
$PM_{2.5}$	0.59	2.1	2.69	2	2.2	4.2
PM_{10}	0.84	5.2	6.04	2.4	5.4	7.8
SOx	17	0.27	17.27	11	0.49	11.49
NMVOC	11	38	49	27	56	83

2.2.2 Natural gas-based electricity production

The fraction of electricity produced by natural gas is expected to steadily rise in the future. It is therefore also expected that natural gas-based mobility (i.e. electrically powered vehicles) will rise as well.

While electric transportation is an exhaust-free emission source, the generation of electricity for charging these vehicles will significantly contribute to their respective environmental burdens[81], and is strongly dependent on the fuel mix used for electricity generation.

Note: Based on 2013 data, Large Combustion Plants (LCPs), which are plants with a total rated thermal input equal to or greater than 50 MW (operated in electricity and heat production, steelworks, gas extraction and so on), emit 46% of SO_2, 18% of NO_X and 39% of mercury across the EU. The BAT[82] Reference Document for LCPs (LCP BREF)[83] sets limits for the emissions to air of new plants as well as tightens the existing emission limits for pollutants including SO_2 and NO_x. National authorities must ensure that the permit conditions for the applicable plants are reviewed based on the updated environmental standards. The document provides, beside BAT-associated emission levels, recommended periodical monitoring practices and best abatement techniques. Section 3.3.2 includes further information on air pollution related to electricity production in the Israeli market.

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[81] Dai, Q., & Lastoskie, C. M. (2014). Life cycle assessment of natural gas-powered personal mobility options. *Energy & fuels*, *28*(9), 5988-5997.

[82] BAT conclusions aim at achieving a high level of protection of the environment as a whole under economically and technically viable conditions.

[83] https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1502972300769&uri=CELEX:32017D1442

3 ESTIMATION OF EMISSIONS FROM THE NATURAL GAS SECTOR IN ISRAEL

Natural Gas is emerging as an important contributor to the Israeli economy from both the economic and the environmental perspectives. Natural gas sourced from Israeli offshore operations is contributing to energy independence and its utilization leads to decreased GHG emissions and reduces the impact on local air quality and population exposure to harmful pollutants. Due to its lower carbon intensity per unit of energy, when compared to other fossil fuels natural gas contributes to a cleaner energy future. However, global data indicates that the temporary slowdown in CO_2 emissions growth from 2014 to 2016 has now been followed by three years of increased emissions. In Israel, a decrease in GHG emissions was apparent from 2012 to 2014 - when locally sourced natural gas was first introduced to the Israeli economy[84]. However, these reductions have stalled from 2015 to 2018 due to increased utilization of natural gas and other fossil fuels. According to Israel's Central Bureau of Statistics, total energy consumption from 2017 to 2018 has increased by only 0.5%, while during the same period electricity consumption has increased by 2.1%[85].

3.1 Natural Gas Outlook for Israel

In recent years the Israeli economy has undergone significant changes in terms of the mix of the fuels consumed, with the discovery of significant natural gas reserves of approximately 900 BCM in the deep waters of the Israeli Exclusive Economic Zone[86]. In 2013 natural gas from Israel's offshore field known as Tamar has been brought online and domestic natural gas production has risen to 6.4 BCM. The growth trend has continued in subsequent years and in 2018 it amounted to 10.44 BCM, which represents a 6.2% increase as compared to 2017. Concurrently, the country also consumes a small amount of imported LNG (0.67 BCM in 2018)[87]. In January 2020 additional domestic natural gas started flowing from the Leviathan gas field, which has recoverable reserves of 605 BCM.

The electricity sector is the main source of demand for natural gas in the Israeli economy, representing about 80% of the amount of natural gas consumed. During the period of 2012-2018 the electricity fuel mix shifted from 61% imported coal and 17% natural gas (in 2012) to natural gas

[84] Ayalon O., Lev-On M., Lev-On P., Shapira N. (2020). Greenhouse Gas Emissions Reporting and Registration System in Israel: Summary of Reports for 2018 Haifa Israel: Samuel Neaman Institute. https://www.neaman.org.il/EN/Greenhouse-Gas-Emissions-Reporting-and-Registration-System-in-Israel-Summary-of-Reports-for-2018

[85] Israel's Central Bureau of Statistics, Energy balance, 2018.

[86] http://www.energy-sea.gov.il/English-Site/Pages/Oil%20And%20Gas%20in%20Israel/History-of-Oil--Gas-Exploration-and-Production-in-Israel.aspx

[87] https://www.gov.il/BlobFolder/reports/ng_2018/he/ng_2018.pdf

rising to 66% with coal declining to only 30% in 2018[88]. The Ministry of Energy (MOE) "Energy Sector Goals for the year 2030"[89] aims at achieving by 2030 zero-electricity production using coal, up to 83% using natural gas, and about 17% or more using renewables.

Figure 7 describes the natural gas consumption in Israel for the period 2013-2018 as well as the amount of natural gas used for electricity generation.

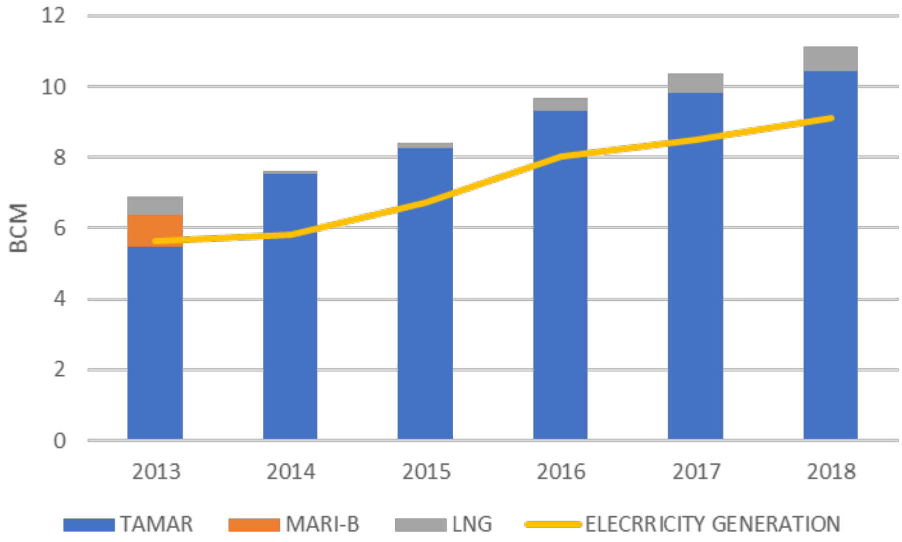

Figure 7: Natural gas for electicity generation and total consumption in Israel for the period 2013-2018

The demand for natural gas in the industrial sector is also on the rise and in recent years there is massive fuel switching in industry from the use of petroleum products to natural gas. The demand for natural gas in the industrial sector in 2018 amounted to 2.02 BCM, which represents an 11.6% increase as compared to 2017, and constitutes 18% of the total natural gas consumed. Future demand for natural gas is expected to grow in the transportation and petrochemical sectors as well.

The projections for natural gas consumption assume a gradual conversion of the transportation sector to natural gas-based fuels. Unlike former projections which considered domestic production of methanol and Gas-to-Liquids (GTL) as major components of the fuel mix, **the most relevant strategic plan** (MOE Energy Sector Goals for the year 2030) **focuses on electric propulsion and CNG.** The envisioned implementation stages include:

[88] The Electricity Authority (2019). Report on State of Electricity Economy – Year 2018. https://pua.gov.il/Publications/PressReleases/Pages/doch_mashek_2018.aspx
[89] https://www.gov.il/BlobFolder/rfp/target2030/he/energy_2030_final.pdf

- **Passenger vehicles** – phasing-in the sale of electric vehicles, with 5% in 2022, 23% in 2025, 61% in 2028, and 100% in 2030[90];
- **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. Also, 10% of heavy-duty trucks and 80% of the light-duty trucks will be fueled by electricity;
- **Buses** – Preliminary penetration target of 25% to be fueled by CNG by 2030 with the rest of the buses having an electric drive.

This study focuses on these two fuel pathways (CNG and electricity) since they are the options preferred also by the Ministry of Environmental Protection (MOEP) due to its anticipated environmental advantages[91] [92]. Even if the WTW emissions from Euro-6 passenger vehicles are compatible, or even lower, than emissions associated with electrical cars (even under the electricity generation scenario for 2030), the later are preferred since the emissions occur from high stacks and are mostly out of densely populated areas[93]. These scenarios are also compatible with the MOE's goal of banning the import of internal combustion vehicles after the year 2030[94]. The government is promoting this approach by removing regulatory barriers and providing economic incentives for infrastructures deployment, vehicle fleets renewal (subsidize the purchasing of CNG trucks, garbage trucks and buses[95]) and through tax benefits.

In 2018, the MOE presented a forecast for natural gas demand until 2042[96], which includes multiple scenarios for natural gas demand in the electricity, industry (including petrochemical industry) and transportation sectors. The 'modest' scenario assumes a 17% reduction in power generation, while the most 'intensive' scenario assumes the shutdown of coal fired power plants and concurrent increase in natural gas demand. Table 12 presents the expected natural gas demand in the transportation sector, based on these two scenarios, for the years 2020-2042.

[90] Under the assumption of 27k, 177k, 665k and 1.4M new electric cars in Israel, respectively.
[91] https://www.gov.il/BlobFolder/rfp/ng_160718/he/ng_presentation.pdf
[92] https://www.gov.il/he/departments/news/minister_elkin_vehicle_pollution_review
[93] https://www.gov.il/BlobFolder/rfp/target2030/he/energy_2030_final.pdf
[94] The main advantage of methanol and GTL is the ability of using them in existing vehicles, which contradicts the vision of the MOE.
[95] http://www.fuelchoicesinitiative.com/activity/buses-purchase/
[96] https://www.gov.il/BlobFolder/rfp/ng_160718/he/ng_presentation.pdf

Table 12: Forecast of natural gas demand in Israel in the transportation sector (BCM)[97]

	2020	2022	2024	2026	2028	2030	2032	2034	2036	2038	2040	2042
'Modest' scenario												
Consumption for electric vehicles	0.1	0.2	0.2	0.2	0.3	0.4	0.6	0.7	0.8	1	1	1.1
Consumption for CNG transportation	0	0	0	0.1	0.3	0.4	0.5	0.7	0.9	1	1.2	1.5
'Intensive' scenario												
Consumption for electric vehicles	0.1	0.2	0.2	0.4	0.6	0.9	1.3	1.8	2.2	2.5	2.6	3.1
Consumption for CNG transportation	0	0	0	0.1	0.3	0.4	0.5	0.7	0.9	1	1.2	1.5

Total projected consumption of natural for the years 2020-2042 amounts to about 13 BCM for CNG fueled transportation, along with either 13 or 31 BCM for electrically charged transportation based on the 'modest' or 'intensive' scenarios, respectively[98].

3.2 Emissions from Fuels Pathways in Israel

Substitution to natural gas from coal or liquid fossil fuels leads to reduced generation of CO_2 during combustion when compared to other fossil fuels but could lead to similar or higher NOx emissions. In a lifecycle context, attention should be given to the air pollution pathways associated with natural gas production, processing, storage, transmission and distribution along with its conversion to alternative transportation fuels. As discussed above, the key air pollutants emitted from the natural gas supply chain are NOx, NMVOC (which is comprised of multiple compounds including HAPs), CO, and PM. In this study we are not addressing SO_2 emissions from natural gas operations since they are below the reporting threshold due to the fact that producing reservoirs along the Israeli shore are 'sweet' (e.g. H_2S < 4 parts per million (ppm) by volume).

Israel is taking various steps to reduce the population exposure to air pollution; it has developed a national plan for general reduction of air pollution[99] and has taken a few steps in addressing

[97] https://www.gov.il/BlobFolder/rfp/ng_160718/he/ng_presentation.pdf
[98] The forecast assumed that adding 100,000 electric vehicles means 2 BCM of natural gas throughout the entire period
[99] MOEP (2013). National Pollution Reduction and Prevention Program. https://www.sviva.gov.il/English/env_topics/AirQuality/Pages/NationalProgramToReduceAndPreventAirPollution.aspx

pollution from the transportation sector[100]. In order for the state of Israel to fully benefit from the use of natural gas, which is an immensely valuable resource, it is imperative to evaluate the potential incremental lifecycle air pollution impacts that may be associated with the various natural gas-based transportation fuels, including electrical charging and natural gas compression pathways. Such impacts may include direct atmospheric emissions of NMVOCs (including air toxics constituents such as benzene), NOx, CO, PM_{10} and $PM_{2.5}$ and formation of secondary pollutants such as O_3.

When developing a national policy for the incorporation of natural gas-based transportation fuels it is important to assemble the latest scientific information on the comparative impacts of the different implementation pathways being considered when compared to business as usual with no new control measures[101]. Such an approach will maximize the benefit of natural gas utilization and ensure minimization of deterioration of air quality and environmental impacts.

Many of the barriers to the use of natural gas-based transportation fuels are technical in nature and overcoming them requires a concerted research and development effort to improve the efficiencies and decrease – or prevent – the emissions associated with the conversion of natural gas to transportation fuels.

Figure 8 presents a schematic description of the expected major emission sources, and the applicable pollutants associated with the different gaseous fuels' pathways, or value chain segments, in Israel.

[100] MOEP (2020). Reducing air pollution from the transportation sector. https://www.gov.il/en/departments/topics/transportation

[101] Ben Zion, Rona, 2014, "Comparison of Environmental Impact of Various Energy Sources for Road Transport in 2020 in Israel", Tel-Aviv University, Master's Thesis, July 2014

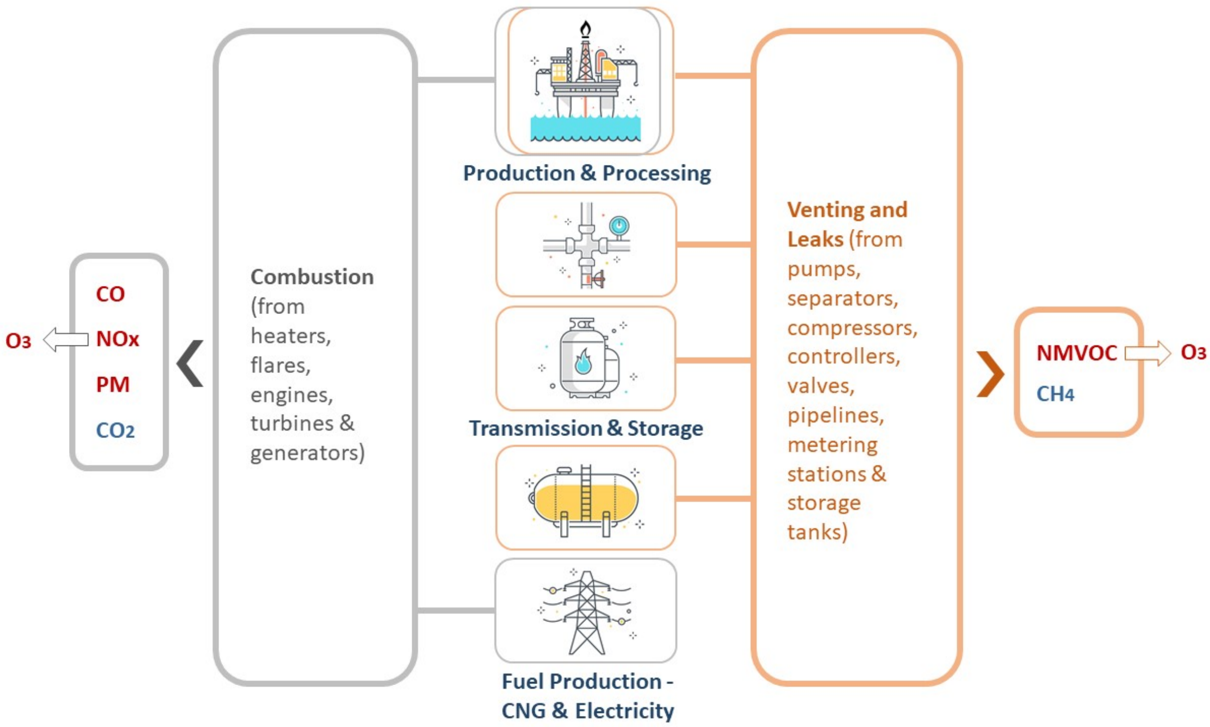

Figure 8: Schematic description of the expected major emission sources in Israel

The emissions from the natural gas fuel cycle encompass:

- Offshore operations that are comprised of production and processing of natural gas. These operations are characterized by emissions from combustion devices, flaring, as well as emissions of venting and leaking from process equipment, such as, pumps, separators, compressors, controllers, and valves.
- Transmission, storage and distribution segments that are comprised of pipelines, metering stations and storage tanks.
- Fuel conversion segment that include emissions associated with the conversion of natural gas to CNG or the emissions that are characteristic to the fuel and technology used for generating the electricity used for charging electrical vehicle.

For CNG, emissions are associated with natural gas compression, storage and dispensing of the resultant CNG into vehicles, along with venting and leakage. For electric vehicles, emissions will vary whether electricity is generated by the combustion of a fossil fuel such as natural gas or is derived from renewable energy.

Combustion emissions include: CO, NOx, PM and CO_2 (which is a GHG but not an air pollutant) while venting emission and equipment leaks are mostly NMVOC and CH_4 (GHG). Both NOx and NMVOC are key elements in the formation of O_3.

3.2.1 Emissions from offshore operations and related onshore facilities

The offshore operations and onshore facilities in Israel, as presented in Figure 9, consist of Mari-B, Tamar platforms and the LNG gasification buoy, and the recently connected Leviathan platform. Both Tamar and Leviathan producing wells are located in the deep-sea west of Haifa (about 90 and 130 km, respectively). The Tamar processing platform is located near the city of Ashdod and is connected to the wells by two 145 km long pipelines (16" diameter pipelines)[102]. The processing platform is in turn connected to the Yam Tethys receiving station, which is located onshore at a distance of 25 km (30" diameter pipeline). The Leviathan processing platform is located 10 km west of Dor beach and is connected via a total pipelines' length of 130 km to the producing wells (18" diameter pipeline)[103,104].

According to the Israel Natural Gas Lines (INGL)[105] the natural gas transmission system is comprised of a 98 km long pipeline along the Israeli coastlines that connects the Yam Tethys and Dor Beach receiving stations (30" diameter pipeline). Additionally, an 8 km pipeline is connecting the LNG gasification buoy to the onshore system at the Hedera power plant (20" diameter pipeline).

[102] https://www.sviva.gov.il/subjectsEnv/SvivaAir/DocLib/tamar/Tamar%20Emissions%20Project%20-%20Performance%20Verificiation%20Report%20Final.pdf
[103] https://www.delekdrilling.co.il/פרוייקט
[104] https://leviathanproject.co.il/about/
[105] https://www.ingl.co.il/נתוני-המערכת/

Figure 9: The offshore operations in Israel[106]

The IL-PRTR presents data about the emissions from Mari-B and Tamar platforms (Mari-B is a processing platform) and from the southern receiving station (Yam Tethys). There is no available data about the LNG gasification buoy, or the transmission system, both offshore and onshore. The Leviathan platform came online only at the tail-end of 2019 and its first full reporting year would be for 2020 operations and will thus start reporting only in 2021.

Table 13 provides data on the emissions of the major pollutants in 2018, as reported by facilities operators to the IL-PRTR, along with the respective percent changes for individual compounds emissions from 2017 to 2018.

[106] Based on: https://www.ingl.co.il/ and https://leviathanproject.co.il/about/

Table 13: Emissions of major pollutants as reported by the facilities operators in the IL-PRTR

Pollutant	2018 Yam Tethys Receiving Station Emissions (Kg/year)	Percent Change from 2017 to 2018	2018 Tamar Platform Emissions (Kg/year)	Percent Change from 2017 to 2018	2018 Mari-B platform Emissions (Kg/year)	Percent Change from 2017 to 2018	2018 Total emissions (Kg/year)
Ethylbenzene	*		26,987	+0.1%	317	-50%	27,304
Benzene	25	-64%	25,591	+0.1%	197	-45%	25,813
Toluene	52	-79%	62,732	+0.1%	167	-48%	62,951
Formaldehyde	56	-75%	719	-8%	356	+17%	1,131
CO	*		64,033	-6%	0		64,033
Xylene – all isomers	*		83,934	+0.1%	294	-50%	84,228
NO_2	*		71,427	-6.5%	*		71,427
NMVOC	3,428	-69.5%	1,205,363	+0.08%	6,990	-47%	1,215,781

* Below reporting threshold

Figure 10 presents the trend of reported CO, NO_2 and NMVOC emissions (kg per year) from the Tamar platform for the period 2013-2018. The figure also depicts the corresponding levels of natural gas supply (BCM) for the same years.

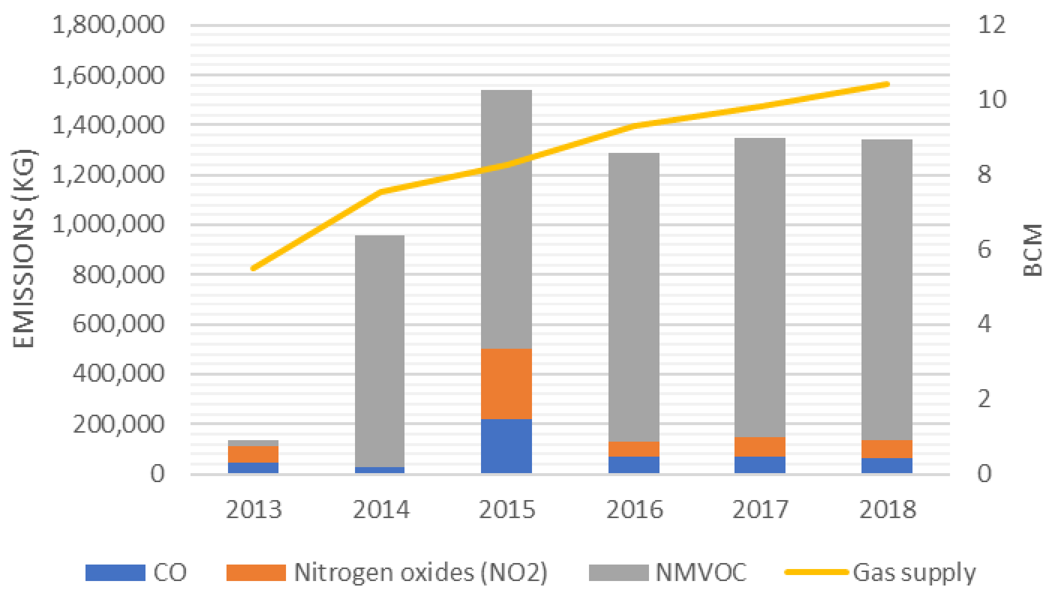

Figure 10: Emissions and gas supply from Tamar platform, 2013-2018

In Figure 10, the upward trend in emissions is consistent with the production growth. However, as shown in Figure 11, we note a different trend in CH_4 emissions (based on the reporting to the IL-

PRTR). Both NMVOC and CH_4 are shown to increase over the period of 2013 to 2015 and starting with 2016 we see a slightly declining CH_4 emission trend while NMVOC continues to increase, though at a more moderate slope.

Figure 12 shows that for the past five years the amount of NMVOC emitted per BCM production is stable, while the CH_4 emissions per BCM produced decreases by 61%. These different trends imply that the economic incentives for CH_4 reduction may not apply to other air pollutants emissions. A similar trend is reported in the IOGP global environmental performance survey, as detailed in Section 2.1.7.3.

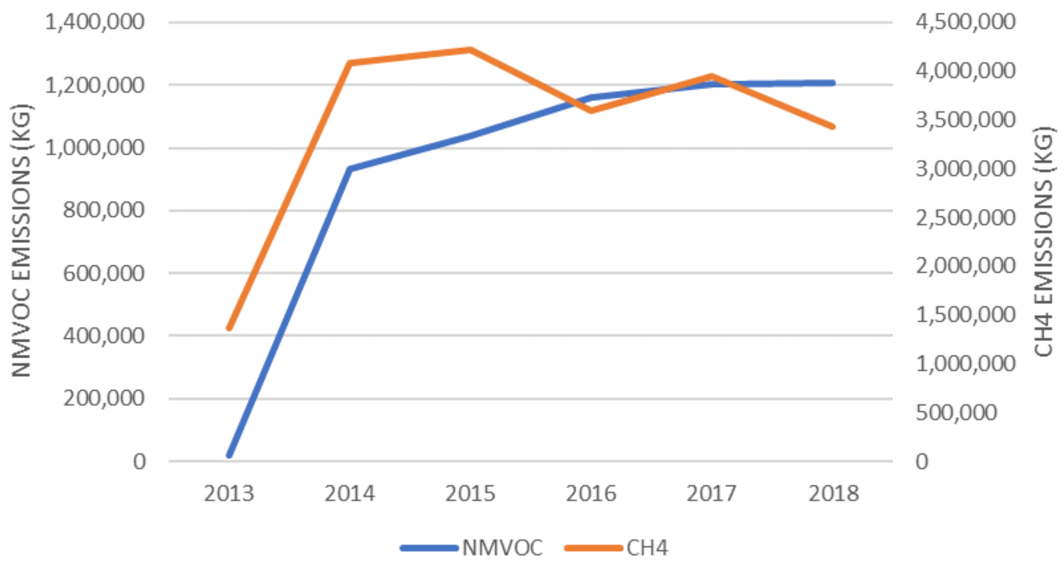

Figure 11: NMVOC and CH_4 emissions from Tamar platform (KG)

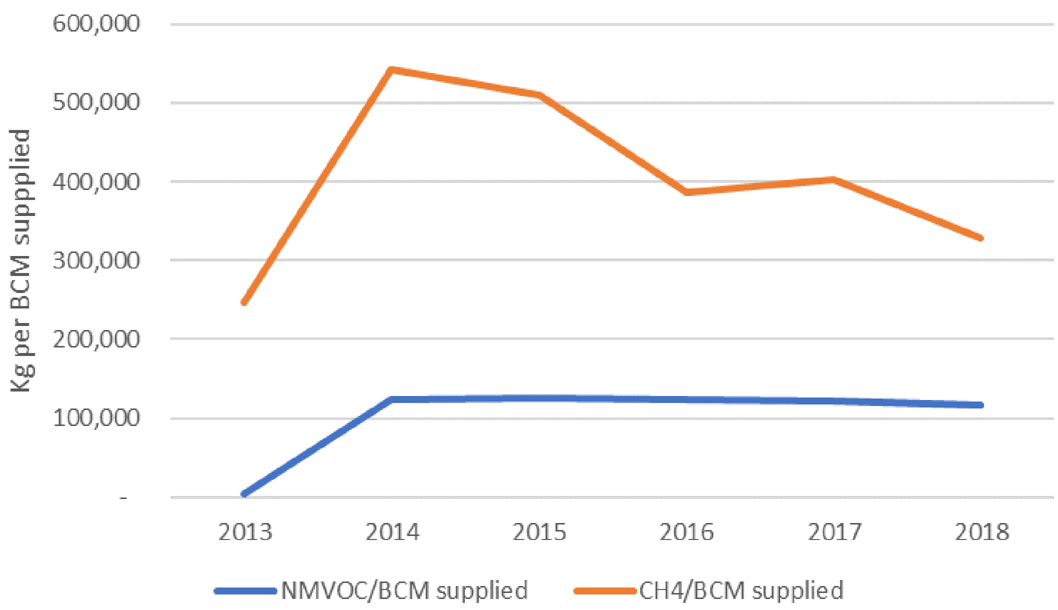

Figure 12: NMVOC and CH_4 emissions from Tamar platform, per BCM produced

According to the INGL[107] the onshore transmission system for the entire state of Israel, is about 600 km long (with pipelines diameter ranging from 10 to 36", with a weighted average of 24"). The system includes three receiving stations (Yam Tethys in the south, LNG gasification buoy at Hedera and the new receiving station at Dor Beach starting at 2020), 48 Pressure Reduction and Metering Systems (PRMS) and 85 Block valve stations.

The only transmission related data reported to the IL-PRTR is from the Yam Tethys's receiving station, with no data being reported for other onshore pipeline connections or other transmission related operations.

3.2.2 Emissions from fuel conversion

3.2.2.1 CNG

Globally, CNG is the most common application for NGVs though LNG use is becoming increasingly common[108], mostly for heavy duty trucks (due to its higher energy density). As of 2019, there is no liquefaction facility in Israel, due to its high development and construction costs (about $10 billion), yet, according to the Knesset Research and Information Center, there is high feasibility for the introduction of CNG propulsion for 90% of heavy duty trucks in Israel, with only 8,000 trucks over 34 ton that cannot meet their fueling needs by CNG[109].

In Israel both "mother" and "daughter" (see Section 2.2.1) station models are in use. As far as we know, natural gas compression facilities and fueling stations are not required to submit an annual report to the IL-PRTR. In addition, National Emissions Inventory includes only the emissions from gasoline fueling stations, and clean air regulations for preventing air pollution from fueling stations[110] consider only liquid fuels.

3.2.2.2 Electricity

The Electricity Authority[111] and the Israel Electric Corporation (IEC)[112] publish official documents about the electricity market in Israel. The information they provide suggests that the main gases

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[107] https://www.ingl.co.il/נתוני-המערכת/

[108] http://www.iangv.org/natural-gas-vehicles/natural-gas/

[109] https://fs.knesset.gov.il/globaldocs/MMM/d922993b-290f-e911-80e7-00155d0aeea3/2_d922993b-290f-e911-80e7-00155d0aeea3_11_13518.pdf

[110] https://www.gov.il/BlobFolder/legalinfo/clean_air_regulations_gas_station/he/transportation_clean_air_regulations_7846_gas_stations072017.pdf

[111] The Electricity Authority (2019). Report on State of Electricity Economy – Year 2018. https://pua.gov.il/publications/documents/pua_electricity_report_2018.pdf

[112] IEC (2019). Environmental report for the years 2017-2018. https://www.iec.co.il/EN/AboutUs/Documents/IECenvironmentalreport2017-2018.pdf; IEC (2019). Sustainability report for 2018. https://www.iec.co.il/Sustainability/Documents/Sustainability_2018.pdf

emitted during the electricity generation process are: SO_2, NOx, PM and CO_2, and the documents present corresponding EFs[113]. The emissions of SO_2, NOx and CO_2 have decreased by 71%, 62% and 37% respectively in the years 2012-2018, due to installation of scrubbers at the coal-powered stations, limitations on use of coal and increased generation with natural gas and renewable energy. However, those EFs are expected to change dramatically with the expanding use of natural gas and renewables. For example, both natural gas and renewables facilities have near zero SO_2 emissions. However, we might see an increase in the emissions of other pollutants, such as NMVOC, which are not reflected currently in these documents.

In order to evaluate the incremental air pollution emissions that may be associated with electric transportation, we have calculated EFs from fuel combustion in the energy sector, for major pollutants. These calculations were performed in accordance with the reports to the IL-PRTR in 2018:

- For electricity generation from coal – we considered the data reported by the Orot Rabin and Rutenberg coal fired power stations.
- For electricity generation from natural gas – we considered the reporting from all the natural gas fired power stations, both IEC's facilities and independent power producers' facilities.
- For electricity generation from renewable energy– we assumed zero emissions (no renewable energy facility reports to IL-PRTR).

For the calculation of EFs (gram emissions per kWh produced) for electricity generation, we initially calculated separate EFs for coal and natural gas generation by dividing the aggregated emissions data - for each of these fuels - by their relative share in the total electricity generation in 2018, as indicated in the Electricity Authority's data[114]. Those unique EFs were subsequently used to produce a weighted average based on the relative share of coal and of natural gas and also of renewables (whose EFs equal zero), in the 2018 fuel mix. We extended this weighted average beyond 2018 in accordance with the projected fuel mix for electricity generation in 2025 (based on the Electricity Authority Report), and on the projected fuel mix for electricity generation in 2030 (based on the MOE Energy Sector Goals for the year 2030).

[113] IEC's EFs for its own facilities (g/kWh produced): SO_2 - 0.63, NOx - 0.88, PM - 0.032. Total electricity production EFs (g/kWh produced): SO_2 - 0.43, NOx - 0.65.

[114] The Electricity Authority (2019). Report on State of Electricity Economy – Year 2018. https://pua.gov.il/publications/documents/pua_electricity_report_2018.pdf

Table 14 presents the average EFs for coal and natural gas fired power generation for 2018 along with the national weighted average EFs for 2018, and the projected EFs for 2025 and 2030.

Table 14: Electricity generation emission factors, according to 2018 data

Pollutant	Calculated **Coal fired power stations** EFs - **2018** (g/kWh produced)	Calculated **natural gas fired power stations** EFs - **2018** (g/kWh produced)	Calculated EFs – for **2018's fuel mix** (g/kWh produced)	Estimated EFs – for projected **2025's fuel mix** (g/kWh produced)	Estimated EFs – for projected **2030's fuel mix** (g/kWh produced)
SO_2	1.433	-	0.428	0.244	-
NO_2	1.784	0.165	0.644	0.420	0.137
PM	0.053	0.011	0.023	0.017	0.009
CO	0.105	0.077	0.083	0.072	0.064
NMVOC	0.000051	0.003751	0.002536	0.002672	0.003114
Ethylbenzene	-	0.000017	0.000011	0.000012	0.000014
Benzene	0.000006	0.000015	0.000012	0.000011	0.000012
Toluene	0.000004	0.000094	0.000064	0.000067	0.000078
Formaldehyde	0.000039	0.000126	0.000096	0.000096	0.000104
Xylene – all isomers	-	0.000039	0.000026	0.000027	0.000032

The calculated EFs in Table 14 show the expected decreasing trend for the years 2018-2030 in the EFs of SO_2, NO_2, PM and CO, due to the switch from solid to gaseous fuels. The results also indicate that the EF for benzene is relatively constant during the same period. At the same time we observe an increase in the projected EFs for NMVOC (22.8%), ethylbenzene (27%), toluene (22%), formaldehyde (8%) and xylene isomers (23%), which is more notable between the years 2025 and 2030 corresponding to the increased fraction of natural gas in the fuel mix.

3.3 Emission Estimation Comparison in Israel

3.3.1 Emissions from natural gas systems

We present a comparison of the emissions reported in the IL-PRTR for the natural gas sector to the average global emissions presented above (Chapter 2). In 2018, the Tamar formation produced 10.44 BCM natural gas as well as 477,000 barrels of condensate[115].

[115] https://www.gov.il/BlobFolder/reports/income_reporte/he/revenue_report_2018.pdf

Based on MOE conversion tables, 10.44 BCM natural gas produced from Tamar in 2018 amount to 7,197 thousand tonnes of natural gas[116]. Additionally, the 477,000 barrels of condensate produced from Tamar in 2018 amount to 64 thousand tonnes of condensate[117]. Hence a total of 7,261 thousand tonnes of hydrocarbons were produced in 2018 from the Tamar formation.

Table 15 presents a comparison between the estimated emissions from the production and processing segments based on the IPCC EFs (Section 2.1.2), the IOGP year 2017 report (Section 2.1.7.3) and the data reported in the IL-PRTR for 2018, as presented in Section 3.2.1. For this comparison of the estimated emissions from the production and processing segments, we multiplied the amount of hydrocarbons produced at Tamar by the global EFs and compared it to the sum of the reported emissions from the gas sector in the IL-PRTR data base. This sum includes emissions reported from the Tamar platform, the Mari-B processing platform and Yam Tethys (where the separation of the light condensate is taking place).

Table 15: Production and processing emissions estimated comparison – IPCC, IOGP and IL-PRTR

	IPCC (tonne)	IOGP Averages emissions (tonne)	IOGP Europe averages emissions (tonne)	IL-PRTR reported emissions (tonne)
NMVOC	7,830-8,665[118]	3,195	1,452	1,216
SO_2		1,452	145	<50*
NO_X		2,687	2,178	71**

* Below reporting threshold

** These low reported emissions are inexplicable

The Tamar platform is in the process of the issuance of an air permit. In the published draft[119], the approved limit of **annual** emissions is 15 tonnes NMVOC and 0.6 tonnes benzene, for daily production of 1.2 BSCFD (Billion Standard Cubic Feet per Day) natural gas and 5,400 barrels per day[120] condensate. As can be seen in Table 15 above, the 2018 reported emissions are much higher than the anticipated permit limit. However, an emissions control project was implemented at the Tamar platform, which became operational since March 31, 2019. The project objective is to reduce

[116] Natural gas density data from MOE conversion tables - 0.6894 kg/m^3
https://www.gov.il/he/departments/guides/natural_gas_conecting?chapterIndex=4
[117] An average value for light and heavy condensate - 850 kg/m^3
http://www.sviva.gov.il/subjectsenv/energy/naturalgas/documents/condensate-2016-report.pdf
[118] The range is due to the level of LDAR program implementation
[119] http://www.sviva.gov.il/subjectsEnv/SvivaAir/DocLib/tamar/tamar-emmision-permit-draft.pdf
[120] This figure is three times higher than – MOEP, 2016. Condensate report.
http://www.sviva.gov.il/subjectsenv/energy/naturalgas/documents/condensate-2016-report.pdf

the emissions of BTEX, NMVOC, and CH_4 from the MEG and TEG vents by 98%[121]. The overall change will be reflected in the reporting for the year 2019.

The emissions permit of the Leviathan platform[122] has a less stringent annual emission limit for NMVOC - 20 tonnes for the same amount of natural gas production (1.2 BSCFD) and 572 m^3/d condensate, but it mandates a more stringent emission cap for benzene - 121 kg for phase A of the operation.

The IPCC EFs can also be used to estimate the NMVOC emissions from other segments of the value chain, as detailed in Table 16. The range of NMVOC values is dependent on the level of LDAR programs implemented and the properties of pipelines material (plastic or other). For estimating emissions from those segments, we used the total natural gas amount consumed in the Israeli market in 2018 – 11.11 BCM[123].

Table 16: NMVOC estimated emissions on different value chain's segments in Israel

Segment	NMVOC Value (tonnes / MCM gas consumption)	Estimated emissions - Lower range (tonnes)	Estimated emissions - Upper range (tonnes)
Gas Transmission	0.02-0.05	222.2	555.5
Gas Storage	0.0040-0.0094	44.4	104.4
Gas Distribution	0.009-0.041	100	455.5
TOTAL emissions		366.6	1,115.4

3.3.2 Emissions from natural gas demand for transportation

The MOE's forecast for natural gas demand until 2042[124] includes a forecast of natural gas demand for CNG transportation at a rate of 0.1, 0.3 and 0.4 BCM in the years 2026, 2028 and 2030, respectively (both in the 'modest' and 'intensive' scenarios). For the Israeli natural gas, the conversion from volume (BCM) to energy content (mmBtu) was performed using the MOE's "Natural gas unit conversion calculator"[125].

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[121] https://www.sviva.gov.il/subjectsEnv/SvivaAir/DocLib/tamar/Tamar%20Emissions%20Project%20-%20Performance%20Verificiation%20Report%20Final.pdf
[122] https://www.gov.il/Files/Sviva/DocLib/leviatan_gas_rig/leviathan-emmision-permit-061119.pdf
[123] https://www.gov.il/BlobFolder/reports/ng_2018/he/ng_2018.pdf
[124] https://www.gov.il/BlobFolder/rfp/ng_160718/he/ng_presentation.pdf
[125] 1 BCM = 35,310,734.46 mmBtu. http://www.energy-sea.gov.il/English-Site/Pages/Data%20and%20Maps/calc.aspx

Table 17 presents the estimated emissions from the WTP segments for CNG transportation according to the EFs in the GREET model, as presented in Section 2.2.1.

The EFs are based on average data for the U.S. market, and a more in-depth study should be conducted to collect country specific data for Israel. In addition, when comparing local air pollution from the WTT segments, one should consider the fact that natural gas is sourced from domestic production in Israel in contrast to other fossil fuels which are mostly imported and just refined locally.

Table 17: Projected emissions from the WTP segment of CNG transportation in Israel

Pollutant	GREET CNG WTP[126] (g/mmBtu)	Estimated CNG WTP emissions for **2026** (tonnes)	Estimated CNG WTP emissions for **2028** (tonnes)	Estimated CNG WTP emissions for **2030** (tonnes)
CO	35	124	371	494
NOx	45	159	477	636
$PM_{2.5}$	0.59	2	6	8
PM_{10}	0.84	3	9	12
SOx	17	60	180	240
NMVOC	11	39	117	155

The data in Table 17 depicts the trend of the projected emissions increase for the years 2026 to 2030 for the listed air pollutants resulting from the incremental production of natural gas and its conversion to CNG for the transportation sector. As discussed above, these are indicative results only since the EFs used (GREET CNG) are representative of the North America natural gas supply chain.

The MOE's forecast for natural gas demand until 2042[127] also includes a forecast of the incremental demand for natural gas for additional electricity generation that would be required for electric vehicles:

- 0.2 and 0.4 BCM in the years 2025 and 2030, respectively - in the 'modest' scenario
- 0.3 and 0.9 BCM in the years 2025 and 2030, respectively - in the 'intensive' scenario

[126] https://greet.es.anl.gov/index.php?content=sampleresults
[127] https://www.gov.il/BlobFolder/rfp/ng_160718/he/ng_presentation.pdf

Table 18 presents the estimated additional emissions due to electricity generation for electric transportation according to the estimated EFs in Israel as presented in Section 3.2.2.2. (Table 14). The calculation considers a rule of thumb that 1 BCM = 4.5 Terawatt-hour[128].

Table 18: Estimated emissions from electricity generation for electric transportation

Pollutant	Estimated emission for **'modest'** scenario – **2025** (tonnes)	Estimated emission for **'modest'** scenario – **2030** (tonnes)	Estimated emission for **'intensive'** scenario – **2025** (tonnes)	Estimated emission for **'intensive'** scenario – **2030** (tonnes)
SO_2	219	-	329	-
NO_2	378	246	567	555
PM	15	16	22	36
CO	65	115	98	258
NMVOC	2.4	5.6	3.6	12.6
Ethylbenzene	0.011	0.026	0.016	0.058
Benzene	0.010	0.022	0.015	0.049
Toluene	0.060	0.140	0.091	0.314
Formaldehyde	0.086	0.187	0.129	0.422
Xylene – all isomers	0.025	0.058	0.037	0.129

The Electricity Authority[129] reports pollutants emissions of 29.852 thousand tonnes of SO_2 and 44.876 thousand tonnes of NO_2 in 2018. Hence, the estimated additional emissions due to electric transportation is estimated to be:

In the 'modest' scenario

- **NO_2** emissions – 0.84% and 0.55% increase in 2025 and 2030, respectively (relative to year 2018 emissions).
- **SO_2** emissions – 0.73% increase in 2025 (relative to year 2018 emissions), and no additional emissions in 2030.
- For other pollutants the increase from 2025 to 2030 is projected to be - 7.5% for PM, 76.2% for CO and in the range of 112-134% for **NMVOC**, **BTEX** and **formaldehyde**.

[128] https://www.gov.il/BlobFolder/rfp/ng_160718/he/ng_presentation.pdf
[129] The Electricity Authority (2019). Report on State of Electricity Economy – Year 2018. https://pua.gov.il/publications/documents/pua_electricity_report_2018.pdf

In the 'intensive' scenario

- **NO_2** emissions – 1.26% and 1.24% increase in 2025 and 2030, respectively (relative to year 2018 emissions).
- **SO_2** emissions – 1.1% increase in 2025 (relative to year 2018 emissions), and no additional emissions in 2030.
- For other pollutants the increase from 2025 to 2030 is projected to be - 61.2% for PM, 164% for CO and in the range of 218-251% for **NMVOC**, **BTEX** and **formaldehyde**.

4 EMISSION MANAGEMENT AND CONTROL

4.1 Air Quality Management Framework

There are two general approaches to regulate air pollution related to emissions from stationary sources:

1. Ambient air quality standards for the major air pollutants mentioned above, and periodically revising these standards based on current scientific information about health impacts and the availability of pollution-reducing technology[130].
2. Implementation plans that are designed to control air pollutants, while tailoring them to specific sources, to attain the respective air quality standards. Such regulations are set to impose specific emission limitations for the construction and operation of facilities including natural gas processing, petroleum refining, storage, transportation, and marketing facilities.

Regulators can also set maximum legal pollutant emission levels and provide guidelines on the appropriate type of pollution control for the emissions of major air pollutants and specific air toxics from certain stationary sources across industries.

In the U.S. and the EU, for example, the major pollutants that are regulated include: CO, NOx, SOx, O_3, PM_{10} and $PM_{2.5}$, and lead[131]. Figure 5 (Section 2.1.5) depicts the declining trends of EU-28 air pollution emissions for SO_2, NH_3, NOx, $PM_{2.5}$, and NMVOC for the period 1990-2017, reflecting the implementation of the clean air directive regulations[132].

An air quality management system needs to be comprised of a set of specific techniques and measures identified and implemented to achieve reductions in air pollution and attain an air quality standard or goal. A robust strategy should encompass the following:

- **Environmental considerations**: factors such as ambient air quality conditions, relevant meteorological conditions, location of the emissions source, noise levels, and any ancillary pollution from the control system itself.
- **Engineering considerations**: factors such as pollutant characteristics (like abrasiveness, reactivity and toxicity), gas stream characteristics, performance characteristics of the control system, and adequate utilities (for example, water for wet scrubbers).

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[130] U.S. EPA – Overview of the Clean Air Act and Air Pollution; https://www.epa.gov/clean-air-act-overview
[131] U.S. EPA, Criteria Air Pollutants; https://www.epa.gov/criteria-air-pollutants
[132] https://ec.europa.eu/eurostat/statistics-explained/index.php/Air_pollution_statistics_-_emission_inventories

- **Compliance considerations**: factors such as capital cost, operating costs, equipment maintenance, equipment lifetime, and administrative, legal, and enforcement costs.

The sections below describe engineering and compliance considerations for attaining the minimization of air emissions to the atmosphere from oil and natural gas operations.

4.2 Control Technologies

4.2.1 NMVOCs control technologies

This section provides an overview of available control technologies for select oil and natural gas industry emission sources. This information is based on data accumulated by the U.S. EPA and compiled in its 2016 guidelines[133].

Table 19 provides a summary of the recommended control techniques for the specified sources. Additional information on emission sources and emission control options is provided in Appendix A.

[133] U.S. EPA (2016); Control Techniques Guidelines for the Oil and Natural Gas Industry, EPA-453/B-16-001, October 2016

Table 19: Summary of the oil & natural gas industry NMVOC emission sources and optional control measures[134]

Emission Source	Applicability	Optional Control Measures	Compliance considerations
Storage Vessels	Individual storage vessel with a potential to emit (PTE) > then specified (e.g. > 6 tpy NMVOC)	Reduce NMVOC emissions from storage vessels by 95% Maintain actual uncontrolled NMVOC emissions at a lower level (e.g. < 4 tpy NMVOC)	– Properly designed, sized, and operated storage vessels are essential to achieve effective emission control. In order to ensure that NMVOC emissions are reduced by at least 95% (the recommended level of control), the storage vessel should be equipped with a cover that is connected through a closed vent system that captures and routes emissions to the control device (or process). – The cover and all openings on the cover (e.g., access hatches, sampling ports, pressure relief valves, and gauge wells) should form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel. Each cover opening should be secured in a closed, sealed position (gasket lid or cap). – The closed vent system should be designed and operated with no detectable emissions (which can be monitored by monthly olfactory, visual and auditory inspections). Any detected defects should be repaired as soon as practicable. – Routing to a process would entail routing emissions via a closed vent system to any enclosed portion of a process unit where the emissions are predominantly recycled and/or consumed as fuel.
Reciprocating Compressors	Individual compressor located between the wellhead and point of custody transfer to the natural gas transmission and storage segment	Reduce NMVOC emissions by replacing reciprocating compressor rod packing on or before 26,000 hours of operation or 36 months since the most recent rod packing replacement. Alternatively, route rod packing emissions to a	– For reciprocating compressors, facility owners should be required to maintain a record of the date of the most recent reciprocating compressor rod packing replacement. – Operators should maintain records of the number of hours of operation and/or track the number of months since the last rod packing replacement for each reciprocating compressor in order to demonstrate that they meet the requirement that the packing is changed out on or before the total number of hours of operation reaches 26,000 hours. – To ensure that NMVOC emissions are reduced by at least 95% from centrifugal wet seal compressors, they should use a control device that is equipped with a cover that is

[134] U.S. EPA (2016); Control Techniques Guidelines for the Oil and Natural Gas Industry, EPA-453/B-16-001, October 2016

Emission Source	Applicability	Optional Control Measures	Compliance considerations
		process through a closed vent system under negative pressure.	connected through a closed vent system that routes the emissions, as described in the section on control device operations and monitoring below.
Centrifugal Compressor	a. Individual compressor using wet seals that is located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. b. Individual centrifugal compressor using dry seals.	a. Reduce NMVOC emissions from each centrifugal compressor wet seal fluid gassing system by 95%. b. No emission controls recommended	
Pneumatic Controllers	a. Individual continuous bleed, natural gas driven pneumatic controller located at a natural gas treatment or processing plant. b. Individual continuous bleed natural gas driven pneumatic	a. Require natural gas bleed rate of 0 Standard Cubic Feet per Hour (scfh) (unless there are functional or safety needs requiring a bleed rate greater than 0 scfh). b. Require natural gas bleed rate less than or equal to 6 scfh	

Emission Source	Applicability	Optional Control Measures	Compliance considerations
	controller located between the wellhead and the natural gas processing plant or point of custody transfer to a liquid pipeline.	(unless there are functional or safety needs requiring a bleed rate greater than 6 scfh)	
Pneumatic Pumps	a. Individual natural gas-driven diaphragm pump located at a natural gas processing plant. b. Individual natural gas-driven diaphragm pump located at a well site.	a. Require zero NMVOC emissions b. Require routing of NMVOC emissions from the pneumatic pump to an existing onsite control device or process Require 95% control unless the onsite existing control device or process cannot achieve 95% If onsite existing device or process cannot achieve 95%, maintain documentation demonstrating the percent reduction	– For diaphragm pumps NMVOC emission control requires capturing emissions and routing to a control device that is connected through a closed vent system that is designed to operate with no detectable emissions (i.e. < 500 ppm using EPA Reference Method 21) – Facility operators should be required to conduct an assessment and certify that the closed vent system is of sufficient design and capacity to ensure that emissions are routed to the control device. – Any detected defects are required to be repaired as soon as practicable.

Emission Source	Applicability	Optional Control Measures	Compliance considerations
		the control device is designed to achieve	
Equipment Leaks	a. Equipment components in NMVOC service located at a natural gas processing plant b. Individual gathering and boosting station located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment or point of custody transfer to a liquid pipeline	a. Implement the 40 CFR part 60, subpart VVa LDAR program for natural gas processing plants b. Develop and implement a **quarterly** Optical Gas Imaging (OGI) monitoring and repair plan that covers the collection of fugitive emissions components at gathering and boosting stations within a company defined area. Method 21 can be used as an alternative to OGI at a 500 ppm repair threshold	– For a natural gas processing plan the required LDAR program should specify monitoring frequency, equipment repair, and recordkeeping and the reporting requirements to document compliance – Monitoring frequencies vary according to the applicable regulation, but are typically weekly, monthly, quarterly and yearly. The monitoring frequency depends on the equipment type and periodic leak rate of the equipment. – For each piece of equipment that is found to be leaking, the first attempt at repair should be made within a reasonable period of time, such as after 5 days from the detection of significant leaks. – First attempts at repair include, but are not limited to, the following best practices, ◦ Tightening of bonnet bolts, ◦ Replacement of bonnet bolts, ◦ Tightening of packing gland nuts, and ◦ Injection of lubricant into lubricated packing. – Any identified source of fugitive emissions should be repaired or replaced as soon as practicable, but no later than 30 calendar days after detection of the fugitive emissions. – If the repair or replacement is technically not feasible, would require equipment blowdown, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next unscheduled, planned or emergency blowdown, or within 2 years, whichever is earlier.

Emission Source	Applicability	Optional Control Measures	Compliance considerations
			– Repaired or replaced fugitive emission components should be required to be resurveyed as soon as practicable, but no later than 30 days after completion of the repair or replacement, to ensure that there is no leak.
Glycol Dehydrators	Individual glycol dehydrator systems including still columns, flash tanks and recirculation pumps	Control vents and flash tank by using either air cooled, water cooled, or glycol cooled condensers with non-condensable gas routed to reboiler burner as fuel is routed to an enclosed combustor or flare Optimize glycol circulation to reduce vent emissions	

Table 20 provides additional information on the cost of primary control technologies for NMVOC emissions sources[129].

Table 20: Cost of primary control technologies for NMVOC emissions sources[a,b]

Emission Source	Control Technology	Emission Reduction	Capital Expenditure	Annual Maintenance	Cost per ton NMVOC reduced
Storage Vessels	VRU	95%	$171,538	$9,396	$2,972
	Combustion Device	95%	$100,986	$14,100	$2,652
Reciprocating compressors (Gathering & Boosting)	Rod packing replacement	1.9 tons NMVOC per compressor per year	$5,650	$2,153	$1,131
Reciprocating compressors (Processing)	Rod packing replacement	4.89 tons NMVOC per compressor per year	$4,280	$1,631	$334
Centrifugal Compressors	Replacing a Wet Seal Compressor with a Dry Seal compressor	87.4% (average NMVOC emission rate reduction from 47.7 Standard cubic feet per minute (scfm) to 6 scfm)	$342,439	$32,324	$1,931
	Routing Wet Seal Fluid Degassing System to a Process	95%	$23,252	$2,553	$141
	Routing Wet Seal Fluid Degassing System to a Combustion Device	95%	$71,783 (new) $23,252 (existing)	$114,146 (new) $3,311 (existing)	$6,292 (new) $183 (existing)
Pneumatic Controllers	Replacing an Existing High-Bleed Pneumatic Controllers with a New Low-Bleed Pneumatic Controller	Reduced NMVOC from 1.47 to 0.06 tpy for Oil and Natural Gas production	$2,698 (per unit)	$296	$209
	Instrument Air Systems (Small - (10HP/13.3kW)	Emission reduction 4.18 tpy	- $17,938	$9,168	$2,804

Emission Source	Control Technology	Emission Reduction	Capital Expenditure	Annual Maintenance	Cost per ton NMVOC reduced
	Instrument Air Systems (Medium - 30HP/40kW)		$77,716	$27,912	$2,227
	Instrument Air Systems (Large - 75HP/100kW)		Large - $143,476	$64,669	$1,747
Pneumatic Pumps	Routing Natural Gas-Driven Pump Emissions to an existing Combustion Device	NMVOC Emission reduction (tpy/pump): Diaphragm Pumps - 0.91 Piston Pump - 0.10		$774	Diaphragm pump - $ 847 Piston pump - $7,709
	Routing Natural Gas-Driven Pump Emissions to a New Combustion Device	NMVOC Emission reduction (tpy/pump): Diaphragm Pumps - 0.91 Piston Pump - 0.10		$21,877	Diaphragm pump - $23,944 Piston pump - $218,017
	Routing Natural Gas-Driven Pump Emissions to an existing VRU	NMVOC Emission reduction (tpy/pump): Diaphragm Pumps - 0.91 Piston Pump - 0.10		$774	Diaphragm pump - $847 Piston pump - $7,709
	Routing Natural Gas-Driven Pump Emissions to a New VRU	NMVOC Emission reduction (tpy/pump): Diaphragm Pumps - 0.91 Piston Pump - 0.10		$24,755	Diaphragm pump - $27,094 Piston pump - $246,697
Equipment Leaks	Processing Model Plant NMVOC Cost of Control - Subpart VVa Option	Annual NMVOC emission reductions processing plant: 4.56 tpy	$8,499	$12,959	$2,844
	Model Plant NMVOC Cost of Control for the **Annual OGI** Monitoring Option	Annual NMVOC emission reductions natural gas well site: 0.61 tpy (40% reduction)	$759	$1,318	$2,158
		Annual NMVOC emission reductions natural gas Gathering &	$2,393	$7,777	$1,990

Emission Source	Control Technology	Emission Reduction	Capital Expenditure	Annual Maintenance	Cost per ton NMVOC reduced
		Boosting station: 3.91 tpy (40% reduction)			
	Model Plant VOC Cost of Control for the **Semiannual OGI** Monitoring Option	Annual NMVOC emission reductions natural gas well site: 0.917 tpy (60% reduction)	$801	$2,285	$2,494
		Annual NMVOC emission reductions natural gas Gathering & Boosting station: 5.86 tpy (60% reduction)	$2,393	$13,534	$2,309
	Model Plant NMVOC Cost of Control for the **Quarterly OGI** Monitoring Option	Annual NMVOC emission reductions natural gas well site: 1.222 tpy (80% reduction)	$885	$4,220	$3,453
		Annual NMVOC emission reductions natural gas Gathering & Boosting station: 7.81 tpy (80% reduction)	$2,393	$25,049	$3,205
	Model Plant VOC Cost of Control for the **Annual Method 21** Monitoring Option	Annual NMVOC emission reductions natural gas well site: 0.645 tpy (42% reduction at 10,000 ppm repair), 1.043 tpy (68% reduction at 500 ppm repair)	$1,418	$2,300	$3,568 (10,000 ppm repair), $2,204 (500 ppm repair)
		Annual NMVOC emission reductions natural gas Gathering & Boosting station: 4.12 tpy (42% reduction at 10,000 ppm repair), 6.67 tpy (68%	$4,283	$9,803	$2,378 (10,000 ppm repair), $1,469 (500 ppm repair)

Emission Source	Control Technology	Emission Reduction	Capital Expenditure	Annual Maintenance	Cost per ton NMVOC reduced
		reduction at 500 ppm repair)			
	Model Plant NMVOC Cost of Control for the **Semiannual Method 21** Monitoring Option	Annual NMVOC emission reductions natural gas well site: 0.873 tpy (55% reduction at 10,000 ppm repair), 1.152 tpy (75% reduction at 500 ppm repair)	$1,460	$3,907	$4,667 (10,000 ppm repair), $3,392 (500 ppm repair)
		Annual NMVOC emission reductions natural gas Gathering & Boosting station: 5.35 tpy (55% reduction at 10,000 ppm repair), 7.37 tpy (75% reduction at 500 ppm repair)	$4,415	$17,292	$3,230 (10,000 ppm repair), $2,348 (500 ppm repair)
	Model Plant NMVOC Cost of Control for the **Quarterly Method 21** Monitoring Option	Annual NMVOC emission reductions natural gas well site: 1.030 tpy (67% reduction at 10,000 ppm repair), 1.26 tpy (83% reduction at 500 ppm repair)	$1,544	$7,121	$6,196 (10,000 ppm repair), $5,651 (500 ppm repair)
		Annual NMVOC emission reductions natural gas Gathering & Boosting station: 6.58 tpy (67% reduction at 10,000 ppm repair), 8.06 tpy (83% reduction at 500 ppm repair)	$4,679	$32,271	$4,901 (10,000 ppm repair), $4,004 (500 ppm repair)

Notes:

[a] Cost data is extracted from EPA's 2016 CTG (see ref. 129) and from State of Colorado Regulatory Analysis for proposed revisions to Rules 3,6 and 7, February 2014

[b] Cost data provided represents only direct expenditures for capital equipment and annual maintenance but does not take into account potential benefits from capturing the emissions

4.2.2 Nitrogen oxides control technologies

In all combustion processes there are three opportunities for NOx formation:

- **Thermal NOx** - The concentration of "thermal NOx" is controlled by the nitrogen and oxygen molar concentrations and the temperature of combustion. Combustion at temperatures below 1,300ºC (2,370ºF) forms much smaller concentrations of thermal NOx.
- **Fuel NOx** - Fuels that contain nitrogen (e.g., coal and oil) create "fuel NOx" that results from oxidation of the already-ionized nitrogen contained in the fuel.
- **Prompt NOx** - Prompt NOx is formed from molecular nitrogen in the air combining with fuel in fuel-rich conditions which exist, to some extent, in all combustion. This nitrogen then oxidizes along with the fuel and becomes NOx during combustion, just like fuel NOx.

Many new combustion systems incorporate NOx prevention methods in their design and generate far less NOx then similar but older systems. New add-on technologies are also common for limiting NOx emissions from external combustion devices (heaters and boilers) and internal combustion devices (engines and turbines).

Primary NOx emission control principles and examples of successful technologies are provided in Table 21[135].

Table 21: Summary of NOx control methods and their efficiencies [136]

Abatement or Emission Control Principle or Method	% Control Efficiency for Gas Turbines	% Control Efficiency for Stationary Internal Combustion Engines	Examples of Successful Technologies
Reducing peak combustion temperature	70 - 85	20-97	– Flue Gas Recirculation (FGR) – Natural Gas Reburning – Low NOx Burners (LNB) – Combustion Optimization – Burners Out of Service (BOOS) – Less Excess Air (LEA) – Inject Water or Steam – Over Fire Air (OFA) – Air Staging – Reduced Air Preheat – Catalytic Combustion
Reducing residence time at peak temperature	70-80	No data	– Inject Air – Inject Fuel – Inject Steam

[135] U.S. EPA (1999), Technical Bulleting: Nitrogen Oxides (NOx) Why and How they are controlled, EPA-456/F-99-006R, November 1999

[136] Based on: Summary of NOx Control Technologies and Their Availability and Extent of Application, EPA 450/3-92-004

Abatement or Emission Control Principle or Method	% Control Efficiency for Gas Turbines	% Control Efficiency for Stationary Internal Combustion Engines	Examples of Successful Technologies
Chemical reduction of NOx	70-90	80-90	– Fuel Reburning (FR) – Low NOx Burners (LNB) – Selective Catalytic Reduction (SCR) – Selective Non-Catalytic Reduction (SNCR)
Oxidation of NOx with subsequent absorption	No data	80-95	– Non-Thermal Plasma Reactor – Inject Oxidant
Removal of nitrogen	No data	No Data	– Use oxygen Instead of air – Ultra-Low Nitrogen Fuel
Using a sorbent	60-90	60-90	– Sorbent in Combustion Chambers – Sorbent in Ducts

4.3 EU Best Available Techniques Guidance

The European Commission initiated an exchange of information in order to develop a Guidance Document on BAT in upstream hydrocarbon exploration and production, with emphasis on environmental protection. The guidance document that emerged has identified BAT and best risk management approaches for selected key environmental issues during onshore and offshore hydrocarbons exploration and production activities[137].

The guidance document, also known as the Hydrocarbon BREF, is a non-binding reference document for the permitting of installations for the exploration and production of hydrocarbons. It provides, among multiple topics, guidance and a common and transparent approach for managing oil and gas air emissions and helps to address public concerns on domestic oil and gas production. The sections below provide an extract of the guidance for BAT as it pertains to offshore flaring and venting along with fugitive emissions management practices.

Additional information on BAT guidance for flaring and venting and for fugitive emissions is provided in Appendix B.

The final air permit for Leviathan and the draft permit for Tamar require implementation of the BAT recommended approach.

[137] EU (2019), Best Available Techniques Guidance Document on upstream hydrocarbon exploration and production, doi: 10.2779/607031, KH-04-19-262-EN-N, February 2019

4.4 Air Permits and Emissions Tracking

Air operating permits are the main tool of addressing the release of air contaminants from upstream oil and natural gas operations. Best practices would require that each major source of air pollutant emissions should obtain an "operating permit" that consolidates all of the air pollution control requirements into a single, comprehensive document covering all aspects of the source's air pollution activities.

Air pollution permits should be required before initiating construction, or undertaking major modification, to existing pollution sources. Operating permits should document how air pollution sources will demonstrate compliance with emission limits and with other applicable requirements by monitoring, either periodically or continuously. They should also document compliance with all other applicable requirements on an-going basis.

Monitoring requirements are a very important aspect of the operating permit since the controlled sources have emissions that are of concern and need to be managed in a systematic way. This is especially pertinent to emissions of NMVOCs, including benzene, among other compounds, which impact regional air quality or are comprised of some known carcinogens that are often present in hydrocarbon emissions from these facilities.

4.4.1 Factors to consider for compliance procedures

Highlights of the main factors to consider when designing an air compliance system to minimize air pollution from oil and natural gas operations are discussed in Appendix A for the primary emission sources. The primary goals of an air quality management system are to ensure that facilities comply with national and local requirements[138].

Regulatory authorities should develop rules and operating permits that can be effectively and efficiently implemented by conducting the following tasks:

- Assessing and documenting compliance with permits and regulations,
- Supporting the enforcement process through evidence collection and case development,
- Monitoring compliance with enforcement orders and decrees,
- Deterring noncompliance by instituting sanctions, and
- Mandating public reporting

[138] U.S. EPA (2016b), Clean Air Act Stationary Source Compliance Monitoring Strategy, October 2016: https://www.epa.gov/sites/production/files/2013-09/documents/cmspolicy.pdf

4.5 Monitoring

Compliance with monitoring requirements is a very important aspect of the operating permit because:

- Monitoring provides facility owners/operators with information they can use to: (a) self-assess their performance relative to meeting air pollution requirements, and (b) assist them in determining the proper corrective actions, when necessary, and
- Monitoring provides the basis for most on-going compliance demonstrations and provides documentation to support the compliance certification required of the owners/operators.

In short, the role of monitoring is to assure compliance with the operating permit conditions and air pollution regulations.

4.5.1 Control device operations and monitoring

If a control device is used to comply with the stipulated 95% NMVOC emission reduction, it is recommended that,

- Device should always operate when gases, vapors, and fumes are vented from the storage vessel subject to NMVOC emission requirements through the closed vent system to the control device.
- Facility operators should be required to follow the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.
- When complying with recommended controls techniques by using a combustion device, it is recommended that a periodic performance testing (no later than 60 months after the initial performance test) be performed to demonstrate initial and continued compliance with the recommended level of control.
- If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process, operators should be required to install and operate a flow indicator at the inlet to the diversion bypass that would trigger a remote alarm when such a diversion occurs.

Facility operators should be required to conduct the following control device compliance assurance measures:

1. Monthly visual inspections or monitoring to confirm that the pilot is lit when vapors are routed to it.

2. Monthly inspections to monitor for visible emissions from the combustion device (such as specified in 40CFR60 Appendix A, Method 22, Section 11).
3. Monthly olfactory, visual and auditory inspections associated with the combustion device to ensure system integrity.

4.5.2 Fugitive emissions monitoring

For detection of fugitive emissions from equipment leaks an operator can use either OGI or a portable sensor that is suitable to perform U.S. EPA Reference Method 21. A plan should be required to implement this monitoring as discussed in Section 4.4 above. The fugitive emissions monitoring plan should cover the collection of fugitive emissions data from equipment components within each company-defined area, including the following minimum elements:

1. Frequency of conducting surveys.
2. Technique for determining fugitive emissions.
3. Manufacturer and model number of fugitive emissions detection equipment to be used.
4. Procedures and timeframes for identifying and repairing components from which fugitive emissions are detected, including timeframes of monitoring components that are unsafe to repair.
5. Procedures and timeframes for verifying component repairs.
6. Records that will be kept and the length of time records will be kept.
7. If an OGI is used, an enhanced quality assurance procedure should be implemented (as shown in the example below)
8. Procedures for calibration and maintenance should comply with those recommended by the manufacturer of the monitoring device used.
9. If monitoring is conducted according to U.S. EPA Reference Method 21[139], the operator should verify that the monitoring equipment meets the requirements specified in Section 6.0 of Method 21 and there are procedures in place for conducting surveys.

Example: Key Elements of an OGI Monitoring Procedure

i. Verification that the OGI equipment meets specification requirements (i.e., capable of imaging gases in a spectral range for the compound of highest concentration in the potential fugitive emissions, must be capable of imaging a gas that is half CH_4 and half propane at a concentration of 10,000 ppm at a flow rate of less than or equal to 60 g/hr from a quarter inch diameter);
ii. Procedure for a daily verification check;

[139] 40 CFR Part 60, Appendix A-7

iii. Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained;
iv. Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold;
v. Procedures for conducting surveys;
vi. Training and experience needed prior to performing surveys; including how the operator will
vii. ensure an adequate thermal background is present in order to view potential fugitive emissions,
viii. deal with adverse monitoring conditions such as wind,
ix. deal with interferences;
x. Procedures for calibration and maintenance.

4.5.3 Advanced monitoring techniques

In the past few years new t have emerged to track emissions from oil and gas operations. Optical remote sensing technologies are well established and can provide high resolution data with low detection limits[140], but could be costly. Lower cost technologies are emerging with more powerful capabilities than before, at a fraction of the cost of typical optical remote sensing technologies. A wide variety of monitoring options is available on the market, and the field of inexpensive sensors is rapidly evolving in terms of sensor availability, price points and sensor quality. The availability of inexpensive wireless communication and networking capabilities enhance the available choices among monitoring systems.

Table 22 provides a high-level summary of the many monitoring technologies suitable for monitoring emissions near upstream oil and gas operations, including leak detection[141]. The categories of sensor technologies presented in the table are based on one of the six principles of operation listed below:

- Optical absorption spectroscopy
- Gas Chromatography
- Photoionization
- Electrochemical
- Semiconductor
- Thermal conductivity

[140] U.S. EPA (2011), Handbook: Optical Remote Sensing for Measurement and Monitoring of Emissions Flux, 2011. at: https://www3.epa.gov/ttnemc01/guidlnd/gd-052.pdf
[141] Environmental Defense Fund (2017), Technology Assessment Report: Air Monitoring Technology Near Upstream Oil and Gas Operations, Prepared by Ramboll Environ, Project Number 0342333A, December 2017

The more costly optical remote sensing technologies (both open path and extractive) are commonly used for fence-line monitoring at onshore facilities and may not be suitable for implementation on offshore oil and gas platforms.

The list makes it clear that a wide variety of sensing technologies are available and ready for deployment depending on the compound of interest and desired detection limit. The goals of any monitoring should be considered and clearly defined in order to select the most appropriate sensor technology. Moreover, it is critical to match the monitoring and sensor qualities to the desired usage, the support facilities it would require for proper operation and the expected level of training for the operators implementing the monitoring in the field.

Table 22: High-level summary of sensor technologies

Sensor Categories	Monitoring Technologies	Compound Classes	Sampling rate	Simultaneous Detection of Multiple Compounds?	General Limit of Detection	Remote capability	Cost Range*	Degree of Market Penetration
Sample Collection	Active Sampling	CH_4, NMVOC, Benzene	Discrete, Time weighted average	Yes	CH_4: < 1 ppm Benzene: < 10 ppb NMOC: < 50 ppb	Yes	Under $1,000 each	Widespread use
	Passive Sampling	CH_4, NMVOC, Benzene	Discrete, Time weighted average	Yes	CH_4: < 1 ppm Benzene: < 10 ppb NMVOC: < 50 ppb	Yes	Under $1,000 each	Widespread use
Open Path Optical/Laser Absorption Spectroscopy	Differential Optical Absorption Spectroscopy (UV-DOAS)	Benzene, NMVOC (monocyclic aromatic hydrocarbons)	Continuous	Yes	Benzene: < 10 ppb NMVOC (monocyclic aromatic hydrocarbons): < 50 ppb	Yes	$60,000-$200,000	Commercially available, limited availability
	Differential Absorption Lidar (DIAL)	CH_4, Benzene, NMVOC	Continuous	No	CH_4: < 1 ppm Benzene: < 10 ppb NMVOC: < 50 ppb	Mobile capable, requires an attendant to move the instrument's location	$295,000 - $445,000	Commercially available, limited availability
	Fourier Transform Infrared Spectroscopy	CH_4, Benzene, NMOC	Continuous	Yes	CH_4: 15-60 ppb Benzene: 30-100 ppb	Yes	$75,000 - $120,000	Commercially available

Sensor Categories	Monitoring Technologies	Compound Classes	Sampling rate	Simultaneous Detection of Multiple Compounds?	General Limit of Detection	Remote capability	Cost Range*	Degree of Market Penetration
	(FTIR)				NMVOC: 1-100 ppb			
	Tunable Diode Laser (TDL) Spectroscopy	CH_4, Benzene	Continuous	No	CH_4: 0.5-1 ppm Benzene: 10-30 ppb	Yes	\$15,000 - \$65,000	Commercially available
	Infrared Camera	CH_4, Benzene, NMVOC	Continuous	No	Qualitative detection only, add-on devices allow for emission rate quantification	Yes	\$50,000 - \$75,000	Commercially Available
	Solar Occultation Flux	CH_4, NMVOC, Benzene	Continuous	Yes	0.5 kg/hr from 50 m downwind or 0.3 mg/m2 across a plane	Mobile capable, requires an attendant to move location	New unit is about \$1,000,000, one month study is \$200,000	None in US, only in Sweden
Extractive (non-open path) Optical/Laser Absorption Spectroscopy	FTIR	CH_4, NMOC, Benzene	Continuous	Yes	CH_4: 15-60 ppb Benzene: 30-100 ppb NMVOC: 1-100 ppb	Yes	\$20,000-\$50,000	Commercially available
	Non-Dispersive Infrared Sensor (NDIR)	CH_4, NMVOC	Continuous	No	CH_4: 1-500 ppm NMVOC: 500-1,000 ppm	Yes	\$1,000-\$10,000	Commercially available
	Tunable Diode Laser (TDL) Spectroscopy	CH_4, Benzene	Continuous	No	CH_4: 0.5-1 ppm Benzene: 10-30 ppb	Yes	\$15,000 - \$50,000	Commercially available
	Cavity-	CH_4,	Continuous	Yes	CH_4:	Yes	\$40,000 -	Commercially

Sensor Categories	Monitoring Technologies	Compound Classes	Sampling rate	Simultaneous Detection of Multiple Compounds?	General Limit of Detection	Remote capability	Cost Range*	Degree of Market Penetration
	Enhanced Spectroscopy	Benzene	or semi-continuous		1-10 ppb Benzene: 0.1-30 ppb		$150,000	available
Chromatography	Mass Spectrometry	Benzene, CH_4, NMVOC	Semi-continuous	Yes	CH_4: < 1 ppm Benzene: < 10 ppb NMOC: < 50 ppb	Yes, if carrier gas is included. Handheld units may have higher detection limits than bench-top units	$20,000 - $60,000	Commercially Available
Ionization	Photoionization Detector (PID)	Benzene NMVOC (mainly aromatics)	Continuous	Yes	Benzene: 2-100 ppb NMOC: 0.05-200 ppm	Yes	$1,000-$10,000	Widespread use
	Flame Ionization Detector (FID)	Benzene, NMVOC, CH_4	Continuous	Yes	CH_4: 1-10 ppm Benzene: 10-100 ppb NMVOC: 50-500 ppb	Yes	$5,000-$50,000	Widespread use
Reactive	Pellistor	CH_4	Continuous	No	CH_4: 100-1,000 ppm	Yes	Under $1,000	Commercially available
	Electrochemical	CH_4, Total VOC	Continuous	No	CH_4: ~100 ppm Total VOC: 100-1,000 ppb	Yes	Under $1,000	Commercially available
	Metal Oxide Semiconductor	CH_4, Total VOC	Continuous	No	CH_4: 10-100 ppm Total VOC: 1-10 ppm	Yes	Under $1,000	Commercially available

* Cost data applies to hardware cost and does not incorporate operating expenses

Section 4.5.2 above focused on leak detection systems for a regulatory setting. One of the key challenges for broader implementation of LDAR programs is improving the efficiency of identification and quantification of fugitive emissions from oil and gas operations. Until recently, only a limited number of standardized measurement methods were approved by most regulators, with emphasis on close-range methods (e.g. Method-21, optical gas imaging). Although such close-range methods are essential for source identification, they can be labor-intensive and there is a need for the incorporation of alternative technologies, which need to be shown as suitable for LDAR programs.

A recent publication[142] has systematically reviewed and compared six technology classes for use in LDAR: handheld instruments, fixed sensors, mobile ground labs (MGLs), unmanned aerial vehicles (UAVs), aircraft, and satellites. These technologies encompass broad spatial and temporal scales of measurement. Minimum detection limits for the technology classes reviewed range from <1 g/hr for EPA Reference Method 21 instruments, to 7.1×10^6 g/hr for the GOSAT satellite, where uncertainties are poorly controlled. To leverage the diverse capabilities of these technologies, the research also recommend a hybrid screening-confirmation approach to LDAR, where screening technology is used to rapidly tag high-emitting sites, which is then followed by direct close-range methods for quantification and tagging leaking components for follow-up maintenance. Currently, fixed sensors, MGLs, UAVs, and aircraft could be used as screening technologies, but their performances must be evaluated under a range of environmental and operational conditions to better check their detection effectiveness.

4.5.4 Startup / Shutdown and Malfunction (SSM)

An important aspect of an air quality management framework is planning for the potential of periods of exceedance of an applicable emission limitation (i.e., excess emissions) due to a startup, shutdown, or malfunction of a source that is subject to a regulatory emission limit:

- **Malfunction** – is defined as an unplanned, "sudden and unavoidable breakdown of process or control equipment." It is possible for a malfunction to occur during source startup, shutdown, or normal operation. Since malfunction emissions are not reasonably foreseeable, they are therefore neither authorized nor considered during the development of an operating permit.

[142] Fox T. A. et al. (2019), Review of close-range and screening technologies for mitigating fugitive methane emissions in upstream oil and gas, *Environ. Res. Lett. 14* (2019) 053002; https://doi.org/10.1088/1748-9326/ab0cc3

- **Startup/Shutdown** – are predictable and/or planned period of operation during which emissions may be higher due to operational considerations or control technology limitations.

The U.S. EPA does not include periods of maintenance as part of its SSM Policy, though several U.S. states have special provisions allowing for excess emissions during periods of maintenance with requirements of compensating for these excess emissions post maintenance[143].

It is recommended that facilities – in conjunction with local authorities – develop SSM compliance plans to address the following activity categories (Table 23)[144]:

Table 23: Elements of SSM compliance plan

Activity Category	Recommended Tasks
Identify potential SSM events	– Review operating procedures – Assess vendor specifications and work orders – Define "begin and end" of startup/shut down events – Review emergency/malfunction reports submitted – Assess excess emissions reports submitted – Conduct on-site interviews with operators, supervisors and managers
Categorize potential SSM events based on similarity and cause	– Planned vs. unplanned events – Routine vs. non-routine events – Authorized vs. unauthorized events – Startup vs. shutdown vs. malfunction – Previously reported vs. not previously reported – Threshold for Reportable vs. non-reportable – Preventive vs. non-preventive
Calculate emissions for potential SSM events	– Uncontrolled emissions estimates – Procedures for immediate SSM event notifications – Periodic deviation or excess emissions reports – Annual emissions inventories
Evaluate options for demonstrating compliance during startup/shutdown and eliminate the cause of upsets	– Develop redundant systems for planned startup/shutdown – Deploy temporary control equipment during startup/shutdown to meet limits – Better manage malfunctions (develop "root cause" analyses)

143 U.S. EPA (1999), Memorandum: State Implementation Plans (SIPs): Policy Regarding Excess Emissions During Malfunctions, Startup, and Shutdown; September 20, 1999.

144 P. Centofanti (2014). EPA's Evolving SSM Policy – The Future of SSM and Affirmative Defense, Trinity Consultants, Environmental Quarterly, Fall 2014

5 CONCLUSIONS and RECOMMENDATIONS FOR IMPLEMENTATION IN ISRAEL

Energy use and economic activity are tightly connected. As Israel attempts to diversify its energy sources, including exploration and production, the use of natural gas is rapidly expanding, taking advantage of discovered resources in the Eastern Mediterranean within Israel's Exclusive Economic Zone. Due to the expansion of offshore operations, broader introduction of natural gas into the Israeli economy and the introduction of new technologies in locations where the industry has never been active before, emissions of associated air pollutants, along with other potential environmental and public health impacts are coming under increasing scrutiny.

The conclusions and recommendations presented hereby stem from the findings of this study, which apply to the natural gas WTT supply chain. The data presented address the air pollution being attributable to the following interlinked operations:

- **Upstream** - comprised of exploration, production, gathering and boosting (compression) operations;
- **Midstream** - entails processing, transmission and storage;
- **Downstream -** refers to conversion of natural gas to fuel and its distribution to end users.

The ultimate goal of the data review and analysis presented is to provide an indication of the air quality impact of the conversion of natural gas to transportation fuels either for delivering CNG or for generating electricity for the purpose of charging electric vehicles. Due to lack of appropriate information, we have not included any data regarding operation of the LNG buoy or emissions associated with support vessels and aircraft to and from the gas platforms. Similarly, no information is provided regarding the emissions' impact of the heavy-duty fleet operating along the gas transmission lines. There is no reliable data regarding these activities and it is not presented in any official government publication.

The emissions associated with natural gas systems include, in addition to GHGs (CO_2, CH_4 and N_2O), other air pollutants (NMVOC, NOx, CO), which are also precursors to the formation of ground level O_3, and which contribute to locally- and regionally elevated air pollution that may also threaten public health. HAPs such as BTEX and more, are part of the NMVOC fraction, which is, by itself, only a fraction of total organic compounds. Benzene, which is a known human carcinogen, and formaldehyde which is another HAP are found in the exhaust of compressor engines. However, the ambient concentration of such air toxics appears to be variable and mostly lower than health-based screening levels.

The study's findings indicate that a wide array of emission sources is associated with natural gas systems, which are comprised of production, processing, transmission, storage and distribution operations. The most common types of equipment contributing to air pollutants' emissions are engines, turbines and other combustion devices in all the operating segments. Additionally, equipment leaks, and routine venting occur during the extraction, processing, and transportation of natural gas to consumers. There are numerous individual equipment components used throughout the natural gas systems that are prone to leaks, including compressors, valves, pumps, flanges, gauges, and pipe connectors. In addition to unintentional leaks, a number of sources are designed to intentionally vent gas during normal operations. These include, for example, pneumatic controllers, pneumatic pumps, storage tanks, dehydrators, and depressurization of equipment before maintenance (blow down).

Emissions Estimation

Various sources were surveyed to ascertain proper EFs for target air pollutants. For example, for NMVOC we provide Tier 1 EFs for the respective natural gas segments, on the basis of the integration of international information compiled by the IPCC (2019 refinement). These Tier 1 EFs are provided by the IPCC for use by countries that do not have detailed data about their industry operations, and they tend to be highly conservative and with wide uncertainty ranges. The IPCC guidelines emphasize that using Tier 2 and Tier 3 methods is highly recommended for developing more accurate and robust emission inventories that will provide a better understanding of the national real- life emissions. Clearly, such an enhanced approach would require the availability of detailed data on national activities and facilities' operation.

Emissions from various processes and operations at natural gas facilities (including natural gas transmission and storage operations) typically contain five different **air toxics** (sometimes referred to as HAPs). These include BTEX and n-hexane. A survey performed by the U.S. EPA[145] aimed to locate and estimate emissions of benzene and other air toxics in order to develop a regulatory control program. The survey concluded that benzene constituted, on average, approximately 0.1% by weight of NMVOC for onshore and offshore gas produced from natural gas wells and it may

[145] U.S. EPA, "Locating and Estimating Air Emissions from Sources of Benzene", EPA-454/R-98-011, Pt.2, 1998

reach the atmosphere due to equipment leaks and other processes. A similar survey would be useful for Israeli natural gas operations in order to quantify accurately the emission potential from local natural gas operations.

As indicated above, natural gas engines are widely used in all segments of the natural gas industry supply chain and are essential to running generators, pumps, compressors, and well-drilling equipment. Most of the pollutants emitted from the operations of these engines are from the exhaust, as described by the U.S. EPA in its AP-42 compilation. Similarly, natural gas turbines are internal combustion engines that operate with rotary rather than reciprocating motion. Turbines are primarily used to power compressors and other equipment. As specified by the U.S. EPA in AP-42, available emissions data indicate that the turbine's operating load has a considerable effect on the resulting emission levels. A brief compilation of applicable EFs for natural gas engines and turbines is presented in this study to make the data readily available for emission estimation.

With the broader introduction of natural gas to the Israeli economy it is imperative to improve the methodology for estimating and reporting emissions to the IL-PRTR and the National Emissions Inventory to properly account for the use of natural gas fueled devices.

Use of Natural Gas for Transportation

When developing a national policy for the incorporation of natural gas-based transportation fuels it is important to assemble the latest scientific information on the comparative impacts of the different implementation pathways being considered as compared to business as usual with no new control measures. Such an approach will maximize the benefit of natural gas utilization and ensure minimization of deterioration of air quality and environmental impacts.

For **CNG-fueled vehicles** the emissions associated with vehicle use, and the on-board combustion system (TTW), dominate the life cycle impacts. In the WTT segment, CNG-fueled vehicles have greater GHG, NOx, SOx and CO emissions than gasoline and lower NMVOC and PM emissions. The emissions are predominately the result of the production and processing phases, with a smaller fraction due to natural gas transmission, compression and fuel dispensing.

With the introduction of natural gas to the vehicle fleet, and the presence of CNG compressors at refueling stations, it is essential to update the emission estimation methodology for refueling stations in order to account for the leakage and venting from natural gas dispensing. It is important to note that Vaturi et al., (2016)[146] have conducted a thorough literature review regarding regulatory requirements of gas fueling stations. These regulations should be studied, adapted and adopted in Israel.

While **electric transportation** is an exhaust-free emission source, the generation of electricity for these vehicles significantly contributes to their respective environmental burdens and is strongly dependent on the fuel mix used for electricity generation. Since the fraction of electricity produced by natural gas is expected to steadily rise in the future, electric vehicles will constitute an important component of natural gas-based mobility.

The **projected incremental emissions** in Israel from the WTP segments **for CNG transportation** in the years 2026, 2028 and 2030, respectively, are presented below. These results are based on the EFs in the GREET model and the projected consumption and conversion of natural gas to CNG in Israel in the respective years:

- CO – 124, 371 and 494 tonnes
- NOx – 159, 477 and 636 tonnes
- $PM_{2.5}$ – 2, 6 and 8 tonnes
- PM_{10} – 3, 9 and 12 tonnes
- SOx – 60, 180 and 240 tonnes
- NMVOC – 39, 117 and 155 tonnes

The **projected incremental emissions** in Israel due to electricity generation **for electric transportation** is presented below. The emission ranges presented are based on the projection of the electricity to be consumed for the 'modest' vs. 'intensive' scenarios in the years 2025 and 2030, respectively:

- CO – 65-98 and 115-258 tonnes
- NO_2 – 378-567 and 246-555 tonnes
- PM – 15-22 and 16-36 tonnes
- SO_2 – 219-329 tonnes (in 2025, no additional emissions in 2030)
- NMVOC – 2.4-3.6 and 5.6-12.6 tonnes
- Benzene – 0.01-0.015 and 0.022-0.049 tonnes

[146] Vaturi, A., Levinson, T., Dror, G. (2016). Legal environmental demands for natural gas station in Israel. Yezreel Valley College. https://www.gov.il/BlobFolder/dynamiccollectorresultitem/research_0418/he/research_sviva_r0418.pdf

Specific Policy Considerations

Although natural gas burns cleaner than coal and petroleum-based fuels, emissions along the natural gas supply chain erase some of its advantages. Therefore, strict emission limits and well-defined operating permit conditions are required to avoid and minimize emissions associated with natural gas.

In Israel, as in many other countries, the regulatory responsibility for environmental management of natural gas operations takes many forms and is distributed among several governmental ministries. Complimentary strategies should be employed within a consolidated framework of "plan-do-check-correct". An integrated approach should be applied to the natural gas industry (upstream, transmission and downstream use) within the context of a robust air quality management system, including:

- **Avoidance and minimization** – Assessment of mitigation and control strategies for storage tanks, fugitive emission leaks, flare and venting systems, chemicals recirculating systems, combustion devices, and pneumatic controllers. This requires adherence to air permit specifications including strict implementation of referenced guidelines for LDAR programs and other work practices to minimize emissions.
- **Monitoring of emissions** – Development of a facility monitoring plan to specify: frequency of measurements of emissions from storage tanks containing process liquids (e.g. condensate or water), annual (or more frequent) surveys of leaking process components[147], installation and calibration of flow meters for flares and vents, metering of fuel gas consumed by combustion devices, and process simulations (or mass balance assessment) for recirculating chemical treatment systems (e.g. glycol dehydrators, and amine sweetening units). The plan should list the specific methods to be used for measuring flows, speciation content of mixtures, and emission rates.
- **Reporting of emissions** – Specification of reporting methodology including data collection as part of annual reporting to the national emissions registry. Reporting requirements should include nationwide natural gas installations both offshore and onshore, including production, processing, transmissions and distribution operations. In designing a reporting

[147] MOEP (2012). Procedure for carrying out LDAR program. https://www.sviva.gov.il/subjectsEnv/SvivaAir/Industry/Documents/%D7%A0%D7%94%D7%9C%D7%99%D7%9D%20%D7%95%D7%94%D7%A0%D7%97%D7%99%D7%95%D7%AA/LDAR_regulation.pdf

program, emphasis should be placed on an integrated ‘facility’ definition approach to avoid exemptions of individual sites as being “below the reporting threshold”.

- **Tracking compliance** – Mandatory periodic reporting to the appropriate air pollution control authority in addition to the annual reporting to IL-PRTR. This compliance reporting should address the actions performed to comply with permit conditions[148]. Additional reports should be submitted regarding any startup, shutdown or maintenance events that caused excess emissions and the steps undertaken to mitigate them.

Table 24 provides a list of specific recommendations to enhance the air quality management program for natural gas operations.

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[148] MOEP (2019). Updated version of reporting format according to air permits. https://www.sviva.gov.il/InfoServices/NewsAndEvents/MessageDoverAndNews/Pages/2019/Annual_Report_Format_Air_Emissions_Permit.aspx

Table 24: Specific recommendations for enhancing air quality management measures

Stage	Measure	Description	Recommendations
Pre-requisite in the current policies	Definition of Air Toxics	• There should be a consolidated list of air toxics that need to be monitored and minimized in order to clarify the guidance provided in TALuft2002 • TALuft2002 Section 5.2.5 specifies organic compounds that are listed in Annex 4. Among them Formaldehyde and Acetaldehyde. Section 5.2.7.1.1 on Carcinogenic Substances Class II specifies benzene but not any of the other compounds listed in the report (which are all hazardous but not carcinogenic) TALUFT2002 list is confusing and may lead to non-compliance due to complexity • Additional compounds that should be considered for inclusion in such a list are ethylbenzene, toluene, xylene isomers, formaldehyde, and hexane	• Establish a list of target HAPs that need to be addressed in air permits issued in Israel. • Conduct periodic surveys to collect activity data and detailed information on potential emissions of the targeted air toxics
Avoidance and minimization	Composition Analysis and ambient air concentrations	• The air permit should specify reference methods for characterization of natural gas and condensate composition • The reference methods selected should provide enough detail to determine content of specific VOCs including air toxics such as BTEX (e.g. ASTM 1945-14 [2019]) • The permits should specify special conditions for continuous air monitoring of air toxics on the platforms. The permit should specify the applicable certification	• Adjust air permits to provide clear guidance for operations throughout the entire supply chain (gas processing, gas transmission, distribution and end use)

Stage	Measure	Description	Recommendations
		standards for the air monitoring equipment	
Avoidance and minimization	Regulated air permits	• Currently no air permits with applicable emission control limits are required for natural gas transmission pipelines • Stations dispensing CNG should be subject to regulatory controls	• High pressure natural gas transmission pipelines and their associated compressor stations as well as low pressure natural gas distribution and CNG at filling stations should be regulated
Avoidance and minimization + monitoring	LDAR Program	• LDAR requirements should be reconciled across different guidance documents and permit requirements • Methodology for LDAR surveys should include specific guidance of OGI with infrared cameras • The program specifications should include maximum allowed time intervals for repairing components that were found leaking • LDAR inspectors should perform verification testing of potential leakage from equipment components, at least on an annual basis	• LDAR should be conducted periodically, in accordance with **specific guidelines**, with its results reported transparently, while ensuring corrective actions are performed as mandated by the regulator
Avoidance and minimization+ Reporting	SSM plans	• Facilities should develop SSM compliance plans to identify potential SSM events and develop options for staying in compliance with emission limits during such events • Malfunctions should be reported on- line immediately to the local authority	• SSM plans should be developed, evaluated by the regulator, and posted on-line to the regulator and the public. Corrective actions should be implemented and reported
Reporting	Emissions reporting	• For the natural gas sector, reporting to the IL-PRTR should be on an integrated company basis to avoid non-reporting for smaller facilities that are below the reporting threshold	• IL-PRTR should include emissions reporting by all natural gas supply chain operations along the transmissions and distribution pipeline routes

Stage	Measure	Description	Recommendations
		• Reporting should include high pressure natural gas transmission pipelines and their associated compressor stations • Reporting should include low pressure natural gas distribution to local customers and dispensing of CNG at filling stations • The IEC and all independent power producers should report their normalized EFs (per kWh) by target compound • Reporting methodology for natural gas operations should be updated to reflect real world operations and emission control techniques • The methodology for natural gas fired engines and turbines should be incorporated in the PRTR calculation tools in addition to emissions from gasoline or distillate fired devices	• Governmental companies (IEC, INGL) should report their annual normalized emissions and not just site- specific ones
Tracking and enhancing compliance	Enhance compliance	• Means to incentivize companies to improve their community relations by creating local advisory committees to jointly track air permits compliance, should be considered • Annual compliance reports including non-compliance events should be disclosed to the public • Public companies should be required to augment their financial reports with non-financial items covering their beyond-compliance commitments	• The MOEP Compliance Rating system should be expanded to include all operations in the natural gas supply chain • Increase enforcement transparency by publishing all inspections, violations and resolution of compliance issues • Ensure that the cost of noncompliance is greater than that of compliance

Supplemental Strategies

In the current situation in Israel, the mistrust among the public, the natural gas companies and the regulator calls for a broader approach that will enable to re-build the trust. The main incredulity characterizes the up-stream gas production.

Israel, as a member of the Organization for Economic Co-operation and Development (OECD), should consider additional strategies that are emerging globally to enhance environmental performance in general, and its potential applicability to natural gas operations in particular:

- **Non-financial disclosure** - EU law requires large companies to disclose certain information on the way they operate and manage social and environmental challenges. This disclosure helps investors, consumers, policy makers and other stakeholders to evaluate the non-financial performance of large companies and encourages these companies to develop a responsible approach to business. The non-financial reporting directive (Directive 2014/95/EU) lays down the rules on disclosure of non-financial and diversity information by large companies. In the EU, companies are required to include non-financial statements in their annual reports from 2018 onwards.
- **Voluntary environmental programs** - Incentives and recognition should be provided for companies to produce environmental public goods beyond the requirements of government law. The main challenges facing such voluntary programs include: motivation to invest resources to create voluntary initiatives, suggesting incentives to join voluntary programs, and clearly specified monitoring and enforcement mechanisms to ensure that participants adhere to program obligations and do not ‘free ride’ on the efforts of other participants. Voluntary initiatives should motivate stakeholders to acknowledge and compensate companies that go beyond compliance.

In conclusion, achieving and maintaining low emissions of air pollutants from natural gas operations is crucial to minimizing air pollution and adverse health impacts in adjacent communities and maximizing the climate benefits of natural gas fuel switching pathways. Significant progress appears possible given the economic benefits of capturing and selling lost natural gas and the availability of proven technologies.

It should also be emphasized that real world detailed emissions data are needed to confidently evaluate the risks of natural gas systems to public health and to the climate and to effectively manage operations.

APPENDICES:

Appendix A: Emission Sources and Emission Control Options

This appendix augments the information provided in Section 4.2.1 on NMVOC control technologies. It is comprised of descriptions of the main NMVOC emission sources along with emission control options for each.

1. Storage vessels

Emissions of the hydrocarbons from storage vessels are a function of flash, breathing (or standing) and working losses:

- **Flash** losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. Flashing losses occur when hydrocarbon liquids flow into an atmospheric storage vessel from a processing vessel (e.g., a separator) operated at a higher pressure. The amount of flash emissions is dependent on the size of the pressure drop, and the liquid temperature.
- **Breathing** losses are the release of gas associated with temperature fluctuations and other equilibrium effects.
- **Working** losses occur when vapors are displaced due to the emptying and filling of storage vessels.

The composition of the vapors from storage vessels varies and the largest component is CH_4. It may also include ethane, butane, propane, and HAP such as BTEX and n-hexane.

Emission Control Options for Storage Vessels

The storage vessel to be controlled should be equipped with a cover that is connected through a closed vent system that captures and routes emissions to the control device (or process). The cover, closed vent system and control device design and compliance measures, should ensure attainment of the required level of control. The cover and all openings on the cover (e.g., access hatches, sampling ports, pressure relief valves, and gauge wells) should form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel. Specifically:

- Storage vessel thief hatch be equipped, maintained and operated with a weight, or other mechanism, to ensure that the lid remains properly seated.
- Gasket material for the hatch is selected based on composition of the fluid in the storage vessel and weather conditions.
- Local agencies require monthly olfactory, visual and auditory inspections of covers for defects that could result in air emissions and any detected defects should be required to be repaired as soon as practicable.

Basic emission control of NMVOC options include:

1. Routing Emissions to a Process via a Vapor Recovery Unit (VRU) – Vapors from the storage vessel are routed back to the inlet line of a separator, to a sales gas line, or to some other line

carrying hydrocarbon fluids for beneficial use, such as use as a fuel. This is often referred to as a VRU when a compressor is used to boost the recovered vapors into the line. VRUs have been shown to reduce NMVOC emissions from storage vessels by over 95% percent.

Notably, a VRU cannot be used in all instances especially if the site lacks appropriate destination for use of the recovered vapor or there is no sufficient electrical power to enable the process. Caution should be taken to prevent drawing air into condensate storage vessels that may constitute an explosion hazard.

2. Routing Emissions to a Combustion Device – Combustors (e.g., enclosed combustion devices, thermal oxidizers and flares that use a high-temperature oxidation process) are also used to control emissions from storage vessels. Combustors can normally handle fluctuations in concentration, flow rate, heating value, and inert species content. The types of combustors installed in the oil and natural gas industry can typically achieve at least 95% control efficiency on a continuing basis.

   An enclosed combustion unit is typically used to control emissions from storage vessels. Such combustors include thermal oxidizers (direct flame incinerators), thermal incinerators, or afterburners. A thermal oxidizer uses burner fuel to maintain a high temperature (typically 800-850°C) within a combustion chamber where the vapors are oxidized (burned) and the combustion by products are emitted to the atmosphere.

2. Compressors

Compressors are mechanical devices that increase the pressure of natural gas allowing it to be transported from the production site, through the supply chain, and to the consumer. The types of compressors that are used by the oil and natural gas industry include primarily reciprocating and centrifugal compressors:

- In a **reciprocating compressor**, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by an internal combustion engine. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder.

  The compressor rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. However, over time, during operation of the compressor, the rings become worn and the packaging system needs to be replaced to prevent excessive leaking from the compression cylinder.

- **In a centrifugal compressor** a rotating disk is used to increase the velocity of the natural gas in a duct section that converts the velocity energy to pressure energy. Such a compressor is primarily used for continuous, stationary transport of natural gas in the processing and transmission systems. Centrifugal compressors may use wet (oil) seals or dry seals to prevent natural gas from escaping where the compressor shaft exits the compressor casing.

The wet seals use oil that is circulated at high pressure to form a barrier against CNG leakage. The circulated oil entrains and adsorbs some CNG that may be released to the atmosphere during the seal oil recirculation process.

Leakage from wet seal centrifugal compressors has been found to be higher than with dry seal compressors primarily due to the off gassing of the entrained natural gas from the oil. This entrained natural gas is not suitable for sale and is either released to the atmosphere, flared, or routed back to a process.

Dry seals prevent leakage by using the opposing force created by hydrodynamic grooves and springs. Dry seal compressors have been found to have lower operation and maintenance costs than wet seal compressors because they are a mechanically simpler design requiring less power to operate and are more reliable.

Emission Control Options for Reciprocating Compressors

Potential control options for reducing NMVOC emissions from reciprocating compressors include control techniques that limit the leaking of natural gas past the piston rod packing. These options include:

1. Specifying the frequency of the compressor **rod packing replacement**, or updating rod packing components to those made from newer materials that can help improve the life and performance of the rod packing system. For example, such a control measure could require the replacement of the packing rings as often as every 3 years (or 26,000 hours of operation) to balance operating cost vs. emission control effectiveness.
2. Increasing or specifying the frequency of **piston rod replacement**. Like the packing rings, piston rods on reciprocating compressors also deteriorate, though more slowly than packing rings, having a life of about 10 years.
3. Requiring the **refitting or realignment of the piston rod** to ensure that the correct fit is maintained between packing rings and the rod may reduce emissions. Also, upgrading piston rods by coating them with tungsten carbide or chrome reduces wear over the life of the rod. Such actions may be part of a regular maintenance program when the compressor is out of service for other maintenance tasks.
4. **Routing of emissions to a process** through a closed vent system under negative pressure. Such a control system would capture the natural gas that would otherwise be vented and route it back to the compressor engine to be used as fuel. The system's computerized air/fuel control system would then adjust the normal fuel supply to accommodate the increased fuel made available from the recovered emissions and thereby take advantage of the recovered emissions while avoiding an overly rich fuel mixture.

Emission Control Options for Centrifugal Compressors

Potential control options to reduce emissions from centrifugal compressors equipped with wet seals include the following control techniques:

1. **Converting wet seals to dry seals** can substantially reduce NMVOC emissions across the rotating shaft compared to wet seals, while simultaneously reducing operating costs and enhancing compressor efficiency. However, it is not practical or feasible in all situations to retrofit an existing wet seal compressor with a dry seal compressor since the conversion process may require a significant period of time to complete and the compressor would need to be out of commission during the conversion period.
2. **Routing emissions to a compressor or fuel gas system** via a closed vent system to any enclosed portion of a process unit (e.g., compressor or fuel gas system). In this approach the emissions are recycled, recovered or consumed as fuel and burned. Emissions that are routed to a process can result in the same, or greater, emission reductions than emissions that are routed through a closed vent system to a combustion device.
3. **Routing wet seal emissions to a combustion device** is similar to the system discussed above for reducing NMVOC emissions from storage vessels. The natural gas removed during the degassing process from the seal oil is directed to a combustion device that achieves 95% control efficiency for NMVOC.

3. Pneumatic controllers

A variety of process control devices are used to operate valves that regulate pressure, flow, temperature and liquid levels. Most instrumentation and control equipment are pneumatic, electrical, or mechanical. Of these, only pneumatic devices are direct sources of air emissions. Pneumatic controllers may be actuated using pressurized natural gas (natural gas-driven) or may be actuated by other means such as a pressurized gas other than natural gas, solar, or electric.

Natural gas-driven pneumatic controllers come in a variety of designs for a variety of uses with multiple emission characteristics:

- **Continuous bleed pneumatic controllers** are used to modulate flow, liquid level, or pressure, and gas is vented continuously at a rate that may vary over time and consist of two types based on their bleed rate:
  a. **Low-bleed**, having a bleed rate of less than or equal to 6 scfh;
  b. **High-bleed**, having a bleed rate of greater than 6 scfh.
- **Intermittent bleed** or snap-acting pneumatic controllers release gas only when they open or close a valve or as they throttle the gas flow.
- **Zero-bleed pneumatic controllers** do not bleed natural gas to the atmosphere. These natural gas-driven pneumatic controllers are self-contained devices that release gas to a downstream pipeline instead of to the atmosphere.

Pneumatic controllers often use available high-pressure natural gas to operate or control a valve, which results in intermittent emissions with every valve actuation, or continuous release from the valve control pilot. Self-contained devices that release natural gas to a downstream pipeline instead of to the atmosphere have no emissions. However, such “closed loop” systems may be applicable only in instances with very low pressure and thus not suitable to replace continuous or intermittent bleed pneumatic devices in many applications.

If a reliable source of electricity is available at a site, controllers can be actuated by an instrument air system that uses compressed air instead of natural gas. Some sites may also use mechanical or electrically powered pneumatic controllers, or solar-powered controllers, if feasible. Although controllers driven by instrument air do not directly emit NMVOC they are a cause of indirect emissions due to the power required to drive the instrument air compressor system.

Emission Control Options for Pneumatic Controllers

Individual pneumatic controllers have relatively small emissions, however, the cumulative NMVOC emissions is significant due to the large number of these devices. The options for reducing NMVOC emissions from pneumatic controllers include:

1. **Replacing high-bleed controllers with low-bleed controllers** or zero-bleed controllers may reduce on average over 1.3 metric tonnes of NMVOC annually per device. There are certain situations in which replacing and retrofitting devices may not be feasible, such as where a minimal response time is needed, or where large valves require a high-bleed rate to actuate, or a safety isolation valve is involved. The U.S. EPA assumes that 80% of high-bleed devices can be replaced with low bleed devices throughout the production segment.
2. **Driving controllers with instrument air** rather than natural gas requires installation of an auxiliary system that consists of:
    a. A compressor driven by an electric motor;
    b. A reliable power source to operate the compressor;
    c. Dehydrators to remove water that condenses when the air is pressurized and cooled (may cause corrosion and blockage of piping and controller orifices);
    d. A tank that holds enough air to allow the system to have an uninterrupted supply of high-pressure air without having to run the air compressor continuously.
3. **Implementing an enhanced maintenance program** can reduce NMVOC emissions due to operating conditions, age and wear of the device. A maintenance program may include at least the following elements: replacement of the filter used to remove debris from the supply gas, replacement of O-rings and/or seals, calibration of the controller or adjustment of the distance between the flapper and nozzle, and inspection for foreign materials lodged in the pilot seat.

4. Pneumatic pumps

Pneumatic pumps are positive displacement, reciprocating units used for injecting precise amounts of chemicals into a process stream or for glycol circulation. Pneumatic pumps often make use of gas pressure where electricity is not readily available, or, if available, the supply gas may be compressed air. For natural gas-driven pneumatic pumps, characteristics that affect NMVOC emissions include the frequency of operation, the size of the unit, the supply gas pressure, and the inlet natural gas composition.

Pneumatic pumps are generally used for one of three purposes:

- Glycol circulation in dehydrators,
- Hot fluid circulation for heat tracing/freeze protection, or
- Chemical injection.

Emission Control Options for Pneumatic Pumps

Natural gas-driven pneumatic pumps emit NMVOC as part of their normal operation. A variety of technologies are available:

1. **Replace natural gas-driven pumps with electric or solar pumps**. Electric or solar pumps provide the same functionality as natural gas-driven pumps. Electric pumps require a reliable source of power while solar pumps can be utilized at remote sites where electricity is not available. However, caution has to be taken as pumps may fail after two to three cloudy days due to insufficient battery charge.
2. **Switch to using instrument air to drive the pumps**. As discussed above for pneumatic controllers, instrument air systems require a compressor, power source, dehydrator, and volume tank. The same pneumatic pumps can be used for natural gas and compressed air, without altering any of the parts of the pneumatic pump, but instrument air eliminates the emissions of natural gas.
3. **Route emissions to a combustion device or a VRU**. Applicable techniques are similar to those discussed above for controlling NMVOC emissions from storage vessels. Similarly, routing emissions from a natural gas-driven pump to an existing combustion device, or a newly installed combustion device does not reduce the volume of natural gas discharged from the pump, but rather combusts the gas and releases the combustion by-products to the atmosphere.

5. Equipment leaks

The emissions and emission controls discussed in this section may apply to all equipment located at a well site, gathering and boosting stations and natural gas processing plant in NMVOC service[149] or in wet gas service[150], and any device or system that is used to control NMVOC emissions (e.g., a closed vent system). Equipment is defined as each pump, pressure relief device, open-ended valve or line, valve and flange or other connector that is in NMVOC service or in wet gas service.

Natural gas processing involves the removal of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. The types of process equipment used to separate the liquids are separators, glycol dehydrators, and amine treaters. In addition, centrifugal and/or reciprocating compressors are used to pressurize and move the natural gas from the processing facility to the transmission stations.

There are several potential sources of equipment leak emissions at natural gas processing plants. Equipment such as pumps, pressure relief devices, valves, flanges, and other connectors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines and valves may leak for reasons other than faulty seals, such as an improperly installed cap on an open-ended line. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions.

[149] For a piece of equipment to be considered not in NMVOC service, it must be determined that the NMVOC content can be reasonably expected never to exceed 10.0 % by weight

[150] For a piece of equipment to be considered in wet gas service, the piece of equipment must contain or contact the field gas before the extraction step at a natural gas processing plant.

Due to the large number of valves, pumps, and other equipment within natural gas processing plants, NMVOC emissions from leaking equipment can be significant.

Emission Control Options for Equipment Leaks

The EPA has determined that leaking equipment, such as valves, pumps, and connectors are a significant source of NMVOC emissions from natural gas processing plants. Controlling fugitive emissions entails the implementation of one or both of the options described below:

1. **Implementing an LDAR program** at natural gas processing plants. Such a program can potentially reduce product losses, increase safety for workers and operators, and decrease exposure of hazardous chemicals to the surrounding community. An effective LDAR program will target leaking equipment by establishing leak definitions and require work practices to mitigate the leaks, such as monitoring leak frequencies from specific types of equipment (i.e., valves, pumps, and connectors). Elements of an effective LDAR program include:
   - Identifying equipment components,
   - Monitoring equipment,
   - Repairing leaking or malfunctioning components,
   - Record keeping and reporting of results.

   Valves and connectors are the primary sources of equipment leak emissions at processing plants because these are the most prevalent equipment components and can number in the thousands. The major cause of emissions from valves and connectors is a seal or gasket failure due to normal wear or improper maintenance.

   A leak is detected whenever the measured concentration exceeds the threshold standard for the applicable regulation (e.g. a leak definition of 500 ppm in 40 CFR 60 subpart VVa), or a plume is detected by OGI using an infrared camera[151].

2. **Conducting an expanded monitoring program using OGI**. Under this measure the site operator develops and implements a Monitoring Plan that covers the collection of fugitive emissions components beyond those in processing plants, i.e. at well sites or compressor stations within a defined operations area.

   A monitoring plan would include:
   - A sitemap with a defined observation path that ensures that all fugitive emissions components are within sight of the path.
   - Specification of methods for inspection and collection of data from all fugitive emissions components.
   - Definition of components subject to inspection such as, connectors, flanges, open-ended lines, valves, pressure relief devices, closed vent systems, compressors, and thief hatches on controlled storage vessels.
   - Determination of monitoring frequency (e.g. quarterly, semi-annually, annually or less frequently)

[151] 40 CFR § 60.18 General control device and work practice requirements: (g) Alternative work practice for monitoring equipment for leaks.

- Provisions to repair or replace fugitive emissions components within a prescribed time frame if evidence of fugitive emissions is discovered during the OGI survey (e.g., any visible emissions from a fugitive emissions component observed using OGI).

6. Glycol dehydrators

TEG is widely used in dehydrators to remove water from natural gas and meet pipeline water content requirements. During the process, wet gas enters near the bottom of the glycol contactor and comes into contact with lean glycol (water poor) in the absorber contact tower. In the contact tower, water in the natural gas is absorbed by circulating glycol and the natural gas is dehydrated and the gas dew point is reduced. The dehydrated gas is referred to as dry gas and exits through the top of the glycol contactor. The glycol that absorbed the water is called rich glycol. The rich glycol then exits from the bottom of the glycol contactor and flows to the regeneration system. The regeneration system typically includes a glycol flash tank (gas-condensate-glycol separator) and a reboiler.

The glycol flash tank (gas-condensate-glycol separator) serves as a separator to recover entrained flash gas and condensate. It also reduces the pressure of the rich glycol prior to entering the reboiler. In the reboiler, the glycol is heated to boil off water from the glycol to produce lean glycol. The lean glycol is cooled using a heat exchanger and pumped back to the glycol contactor to continue the cycle. Typical dry gas pipeline requirements can range from 5 to 7 lbs water per Millions of Standard Cubic Feet (MMSCF) of natural gas. Further process details are available from the GPSA[152].

A glycol circulation pump is used to circulate glycol through the system. There are many varieties of pumps used including Kimray positive displacement (gas-injection) pumps, other pneumatic pumps and electric reciprocating and centrifugal pumps. Larger glycol dehydrators often use electric motor-driven pumps.

The reboiler uses a still column (reflux condenser coil) to separate water from the glycol. The still column's vent gas will contain water vapor and hydrocarbons such as CH_4, BTEX, n-hexane and other VOCs.

Flash gas liberated from the flash tank (located between glycol contactor and reboiler) will be natural gas that is mostly CH_4 and some NMVOCs and small amounts of BTEX. Regeneration of the rich glycol in the glycol reboiler causes CH_4, NMVOCs and HAPs to be released with the water vapor exiting the still column vent.

In summary, the sources and types of air pollution from a TEG glycol dehydrator include the following:

1. **Still Column Vent** – water, CH_4, VOCs, BTEX, n-hexane, 2,2,4-trimethylpentane
2. **Flash Tank** – primarily natural gas similar to fuel gas (mainly CH_4 and some NMVOC and BTEX)

[152] GPSA Engineering Data Book, 13th Edition, Volume II; See glycol dehydrator schematics at https://petrowiki.org/File:Vol3_Page_202_Image_0001.png

3. **Glycol pumps** using high pressure natural gas – primarily natural gas similar to fuel gas.

Emission Control Options for Glycol Dehydrators

Natural gas streams contain varying amounts of CH_4, NMVOCs and HAP. HAPs in natural gas include BTEX, n-hexane and 2,2,4-trimethylpentane. These HAPs are slightly soluble in the TEG used and as a result, HAPs are absorbed in the glycol contactor. Also CH_4 and NMVOCs (other than BTEX) will be entrained in the rich glycol due to the high operating pressure of the glycol contactor (600 to >1000 psig).

1. **Still Column Vent Emission Control**
   - Air cooled condensers with non-condensable gases vented to the atmosphere,
   - Water or glycol cooled condensers with non-condensable gases vented to the atmosphere,
   - Air cooled, water cooled and glycol cooled condensers with non-condensable gas routed to reboiler burner as fuel or routed to an enclosed combustor or flare,
   - Air -cooled or water- cooled condensers with non-condensable gas routed to a VRU
2. **Glycol Flash Tank Emission Control**
   - The glycol flash tank is a pressure vessel (operating pressure range of 60 to 120 psig) and has a similar makeup as fuel gas.
   - This gas is typically routed back to the system (e.g., fuel gas) or controlled using a VRU, flare or enclosed combustor.
3. **Optimization Techniques to Reduce Emissions** (based on EPA's Natural Gas Star Recommendations) Limit glycol circulation rate to only what is needed to dehydrate the gas to the required lbs/MMSCF, and use electric glycol circulating pumps instead of gas operated pumps.
4. **Zero emissions dehydrators** that combine several technologies to virtually eliminate CH_4 and NMVOC emissions.
   - Install flash tanks, electric pumps and electric control valves, which reduce emissions by avoiding use of natural gas to drive pneumatic controllers.
   - Design a system to collect all condensable components from the still column vapor and use the remaining non-condensable still vapor (CH_4 and ethane) as fuel for the glycol reboiler.

Appendix B: Best Available Techniques

This appendix augments the information provided in Section 4.3 on EU BAT guidance. It focuses on BAT for Flaring & Venting and Fugitive Emissions.

1. Flaring & Venting – Best Available Techniques

The following techniques are considered BAT for flaring and venting under EU guidance[153]:

Flaring

- Implement source gas reduction measures to the maximum extent possible, including ensuring that hydrocarbon processing plant and/or equipment is designed for optimal efficiency and reliability.
- Minimize venting of hydrocarbons from purges and pilots, without compromising safety, through measures including installation of purge gas reduction devices, flare gas recovery units and inert purge gas.
- Provide auxiliary power to prevent trips to flare. Consider either "continuously lit pilots" or "ignition-on-demand" as the primary ignition system. These can eliminate or at least minimize delay in achieving an ignited flare; and reliability of the ignition system.
- For new facilities or when making modifications to existing facilities, specify efficient flare tips, taking into account: combustion efficiency, optimized size and number of burning nozzles, and variability of flaring rates and gas composition; and optimize the flare design according to process conditions over the expected field life.
- Specify a reliable flare pilot ignition system including an adequate supply of pilot gas with a sufficiently high calorific value, a pilot flame detection system and wind guards.
- Use flares with windshields on pilot burners as well as on the main burner, to improve combustion efficiency by deferring side-wind impacts and reducing disturbance due to light from flare.
- Perform flare monitoring to detect and address conditions that indicate inefficient combustion such as flame lift off, flame lick or visible black smoke.
- Regularly analyze gas sent to flaring and associated parameters of combustion (e.g. flow gas mixture and heat content, ratio of assistance, velocity, purge gas flow rate, pollutant emissions).
- Perform flare inspection, maintenance and replacement programs to ensure continued flare efficiency.
- In addition, consider implementing flare noise avoidance measures including:
    - Installing injectors in a way that allows jet streams to interact and reduce mixing noise.
    - Increasing efficiency of the suppressant with better and more responsive forms of control.

Venting

- Design to route low pressure atmospheric vents (for example from glycol dehydrators) to flare gas recovery, or where this is not feasible to flare.

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[153] EU (2019), Best Available Techniques Guidance Document on upstream hydrocarbon exploration and production, doi: 10.2779/607031, KH-04-19-262-EN-N, February 2019; Section 21 Offshore Activity: Flaring and Venting

- Use an inert gas (e.g. nitrogen) as a stripping and flotation gas in dissolved gas flotation systems used for treating waste water; as a secondary seal gas in mechanical compressor seals; and as a purge or blanket gas in storage tanks (e.g. crude oil storage tanks or medium expansion tanks).
- Use hydrocarbon gas for Floating Production, Storage and Offloading (FPSO) storage tanks/blanketing that can be recovered instead of vented.

2. Fugitive Emissions – Best Available Techniques

The following techniques are considered BAT for the management of fugitive emissions under EU guidance[154]:

Design Considerations

- Limit the number of potential emission sources.
- Maximize inherent process containment features.
- Minimize use of flanges and other potential leak paths.
- Select high integrity equipment including valves, flanges, packings, seals and equivalent fugitive sources, to minimize leakage to the external environment.
- Consider welded piping for high and low-pressure lines containing hydrocarbon inventory.
- Specify valves with double packing seals.
- Have preferences for zero bleed pneumatic controllers over hydrocarbon gas-driven controllers.
- Use magnetically driven pumps/compressors/agitators) where practicable.
- Use pumps/compressors/agitators fitted with mechanical seals instead of packing.
- Specify high-integrity gaskets (such as spiral wound, ring joints) for critical applications.
- Where practical, facilitate monitoring and maintenance activities by providing ease of access to potentially leaking components.
- Select appropriate centrifugal compressor seals - Seals on the shafts of centrifugal compressors designed to prevent gas from escaping the compressor casing. These may use oil (wet seals) or mechanical seals (dry seals). Wet seals result in gas being entrained in the oil and then released when the oil leaves the compressor, resulting in a constant fugitive emission during compressor operation. Although dry seals do not use oil, some fugitive emission is still associated with gas escaping around the rotating compressor shaft, which is considered unavoidable and is also present in wet seals.
- Ensure appropriate fixed fire and gas (F&G) detection systems specified to detect larger volume emissions

Operations Considerations

- Sniffing method – Undertake leak detection using hand-held personal analyzers, to identify leaking components by measuring the concentration of hydrocarbon vapors in the immediate vicinity of the leak with a flame ionization detector (FID), a semi-conductive detector or a PID

[154] EU (2019), Best Available Techniques Guidance Document on upstream hydrocarbon exploration and production, doi: 10.2779/607031, KH-04-19-262-EN-N, February 2019; Section 22 Offshore Activity: management of Fugitive Emissions

(photo ionization detector). The selection of the most suitable type of detector depends on the nature of the substance to be detected.

- OGI method – Undertake leak detection using hand-held cameras that can visualize the release of gas using spectroscopic techniques. Ongoing developments in the field may eventually lead to OGI being able to provide quantified emissions measurements. OGI cameras are used as part of routine processes and provide a useful means of identifying the presence of small volume leaks and seeps, especially in otherwise inaccessible facility areas. User training and competency maintenance are essential.
- Assurance and verification – Ensure that the breaking and re-making of flanged joints, including leak testing, is adequately covered by maintenance procedures as part of the facility planned maintenance system.
- Real time CH_4 detection – A range of quantification techniques are currently emerging which may in the future offer the opportunity to quantify emissions from a facility at a broad scale. These include solar occultation flux (SOF) or differential absorption LiDAR (DIAL) campaigns. They are included to provide context for future developments only and should not be considered representative of current BAT.

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