Quantification of ABAG POWER's Natural Gas Emissions

ABAG POWER Executive Committee Meeting
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Association of Bay Area Governments

METROPOLITAN TRANSPORTATION COMMISSION

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Agenda

- The Project
- Why it Matters
- Scope of Quantified Carbon Emissions
- Overlap with Existing Emissions Reductions Programs
- Recommended Framework
- Potential Next Steps

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The Project

In 2021, ABAG POWER engaged with members and stakeholders to identify and evaluate preferred GHG emission reduction programs. The resulting consensus was that ABAG POWER should consider carbon offsets and other options (electrification, renewable natural gas, etc.) to help Members reach their climate goals.

In 2022, following a competitive procurement, GPT was awarded a contract including the following scope of work:

Research and analyze methodologies and recommend one or more methodology to quantify each ABAG POWER member's annual (fiscal year) greenhouse gas (GHG) emissions associated with the natural gas usage for enrolled accounts.

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Why it Matters

- This process begins to account for the environmental cost of our core product – **a shift from the "least cost commodity" perspective**
- Identifying and investing in local carbon reduction opportunities can be a valuable offering that aligns with ABAG POWER's mission to support the goals of its member agencies
- A transition to a "carbon neutral" default product was identified as a near-term strategy of the Strategic Implementation Roadmap
  - ➢Enacting this transition with transparency builds trust and allows us to avoid the perception of greenwashing

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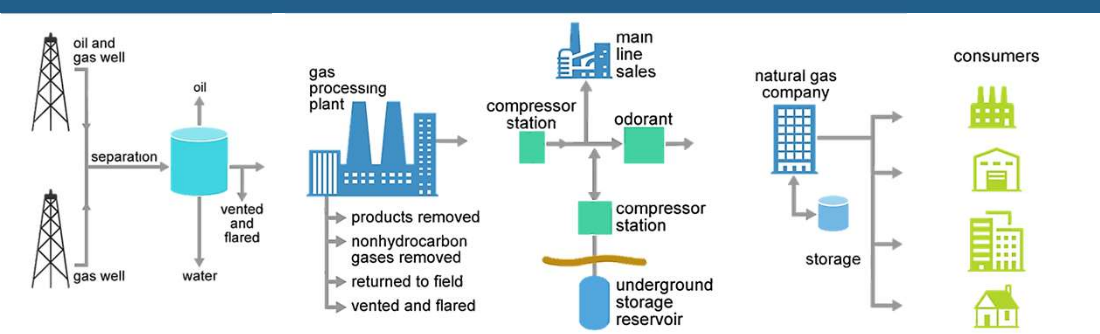
Scope of Quantified Carbon Emissions

- Emissions caused by ***metered usage*** (e.g., consumer natural gas combustion)
- Emissions caused by local ***distribution*** of natural gas on the utility system
- Emissions caused by producing, processing, storing, and transporting natural gas on the transmission system ("***upstream*** emissions"; presented in low, nominal, and high scenarios)

Summary of Emissions Sources



22.1%
Upstream

Production (12.7%)
Natural gas wells used for natural gas production.

Processing (2.1%)
Acid gas removal, dehydration, and sweetening.

Transport & Storage (7.3%)
Interstate and intrastate pipelines used for delivering natural gas.

18.8%
Distribution
Local distribution of natural gas.

59.1%
Metered Usage
Natural gas metered consumption.

EPA Source for Upstream % Breakdown Nominal Case: Environmental Protection Agency
eia Source for Graphic: U.S. Energy Information Administration

Methodologies - Metered Usage

Greenhouse Gas (GHG) Equivalencies – CO_2 per Therm

Palo Alto Utilities	PG&E	StopWaste	CA Air Resources Board (CARB)
Metered **0.005302** mt CO_2 per Therm	**Metered** 11.7 lbs CO_2 per Therm	**Metered** 0.005302 mt CO_2 per Therm	**Metered** 0.005302 mt CO_2 per Therm
Applied to metered Therms.	Applied to metered Therms. Equates to **~0.005307** mt CO_2 per Therm, used in PG&E's corporate reporting.	Applied to metered Therms.	Applied to metered Therms.

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Quantified Emissions – Metered Usage

FY 21-22 Usage	6,675,907 therms	
	X	
Metered Usage Emissions Methodology	0.005302 mt CO_2 per Therm	
	=	
FY 21-22 Metered Usage Emissions	35,396 mt CO_2e	

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Methodologies – Distribution

- PG&E provides a breakdown of their current distribution "shrinkage" factors.
  - "*In-kind shrinkage allowances collect the lost and unaccounted for gas and the utility fuel use attributable to the volume of natural gas received by PG&E for transmission, distribution and storage service.*"
- The shrinkage volumes allocated to ***compressor fuel*** (Gas Department Use, "GDU") is 26.65% of the system forecasted shrinkage volume
- The shrinkage volumes allocated to ***fugitive natural gas*** (Lost and Unaccounted For, "LUAF") is 73.35% of the system forecasted shrinkage volume

LUAF & GDU Allocations to Transmission and Distribution

		System Forecast	Core	Noncore	Off-system	NC Trans.	NC Distr.	
	LUAF Calculations:							
17	LUAF allocated volumes (less off-sys LUAF; core/noncore 78%/22%)	11,570	8,756	2,470	344			17
18	Throughput per forecast (Mdth)	715,280	258,277	352,724	104,278			18
19	Less: SEGDA	0		0				19
20	Totals for Calculation of allocation	715,280	258,277	352,724	104,278			20
21	LUAF as % of throughput (Lines 17/20)	1.618%	3.390%	0.700%	0.330%			21
22	Noncore Trans. LUAF% ((D) line 21 - wtd. per surveys above)					0.678%		22
23	Noncore Distr. LUAF% (D) line 21 - wtd. per surveys above)						0.885%	23
24	Off-System LUAF (per D.94-02-042)	0.33%						24
	GDU Calculations:							
25	GDU per forecast(Mdth) - Pipeline (Total Plus balancing service storage GDU)	4,204						25
26	GDU % = (B) line 24/(B) line 20	0.588%						26
	Shrinkage (LUAF+GDU)							
27	Noncore Transmission = (B) line 26 + (E) line 22	1.266%						27
28	Noncore Distribution = (B) line 26 + (F) line 23	1.472%						28
29	Core Total = (B) line 26 + (C) line 21	3.978%						29
30	Core Distribution = (B) line 29 - (B) line 27	2.712%						30
31	Off-System Transmission = (B) line 26 + (B) line 24	0.918%						31

Source: *PG&E Advice Letter 4651-G*

Methodologies – Distribution

- PG&E publishes rate schedules that apply shrinkage rates to core and non-core metered natural gas volumes.
- The resulting shrinkage volumes allocated to compressor fuel (26.65%) are multiplied by CARB's emission factor to compute the ***compressor fuel*** combustion portion of the distribution emissions
- The resulting shrinkage volumes allocated to fugitive natural gas (73.35%) are multiplied by CARB's emission factor and CH_4 equivalency (25x) to compute the ***fugitive*** portion of the distribution emissions

	Season	Core	Noncore on Distribution System
As of Nov. 1, 2022	Summer (Apr - Oct)	1.0%	0.2%
	Winter (Nov - Mar)	3.7%	0.2%
As of Apr. 1, 2021	Summer (Apr - Oct)	0.8%	0.1%
	Winter (Nov - Mar)	2.7%	0.1%

Source: https://www.pge.com/pipeline/products/rates/new_shrink/index.page

Quantified Emissions – Distribution (sample)

Timeframe: Summer (Jul '21 – Oct '21)

Fugitive:

Usage (Therms) X PG&E Distribution Shrinkage Factor = Distribution shrinkage volume (Therms) X **Fugitive %** X CARB Emissions Factor X CARB CH_4 Equivalency = Distribution Fugitive Emissions

	Usage (Therms)	PG&E Distribution Shrinkage Factor	Distribution shrinkage volume (Therms)	Fugitive %
Core	1,401,023	0.8%	11,208	73.35%
Non-core	252,519	0.1%	253	73.35%

CARB Emissions Factor: 0.005302 mt CO_2 per Therm

CARB CH_4 Equivalency: 25

Distribution Fugitive Emissions: 1,114.2 mt CO_2e

Combustion:

Usage (Therms) X PG&E Distribution Shrinkage Factor = Distribution shrinkage volume (Therms) X **Combustion %** X CARB Emissions Factor = Distribution Compressor Fuel Emissions

	Usage (Therms)	PG&E Distribution Shrinkage Factor	Distribution shrinkage volume (Therms)	Combustion %
Core	1,401,023	0.8%	11,208	26.65%
Non-core	252,519	0.1%	253	26.65%

CARB Emissions Factor: 0.005302 mt CO_2 per Therm

Distribution Compressor Fuel Emissions: 16.2 mt CO_2e

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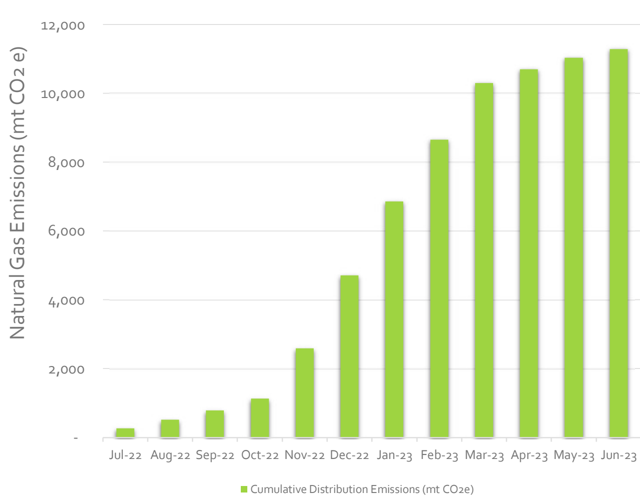
Quantified Emissions - Distribution

	Fugitive	Combustion
FY 21-22 Distribution Shrinkage	85,885 therms	30,480 therms
	X	X
CARB Emission Factor	0.005302 mt CO_2 per Therm	0.005302 mt CO_2 per Therm
	X	
CARB CH_4 Equivalency	25	

=

FY 21-22 Distribution Emissions: 11,280 mt CO_2e



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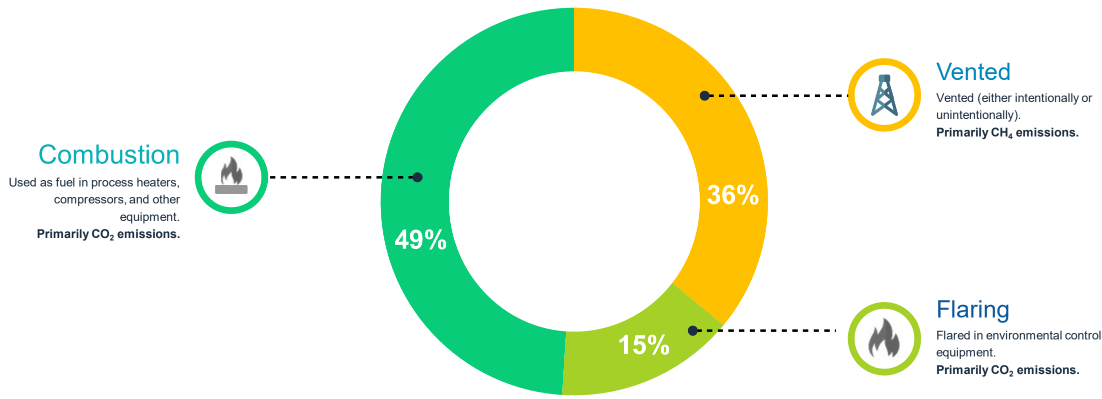
Methodology – Upstream



The percentage values of the contribution of major emission sources were taken from the Life Cycle Analysis of Natural Gas Extraction and Power Generation, May 29, 2014. The report was prepared by Energy Sector Planning and Analysis (ESPA) for the United States Department of Energy (DOE), National Energy Technology Laboratory (NETL).

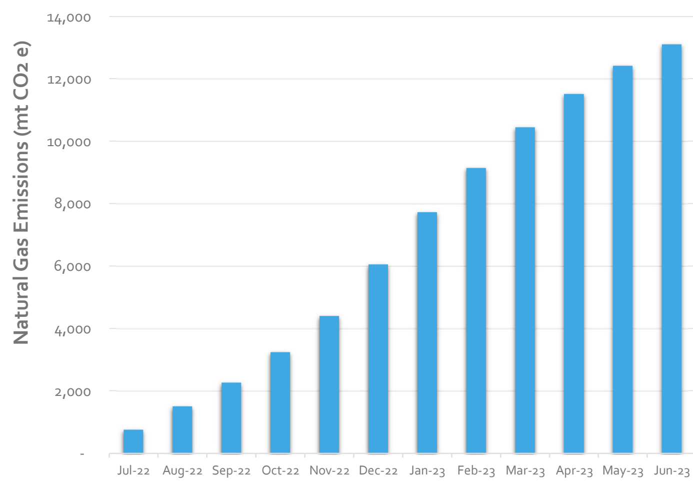
National Energy Technology Laboratory Natural Gas Lifecycle Analysis Conclusions

- The uncertainty in results for natural gas systems is driven by variability in the underlying data. The multiple scenarios in this analysis are a combination of different production basins and extraction technologies; they show that geographic and technological variability is a large source of uncertainty. More research and analysis is necessary to identify other drivers of uncertainty (e.g., variability in infrastructure age, variability in operator practices, temporal inconsistencies within data, and errors in data collection and reporting).
- The national average life cycle GHG emissions from the natural gas supply chain are 19.9 g CO2e/MJ (with a mean confidence interval of 13.1 to 28.7 g CO2e/MJ). The CH_4 emission rate for the national average is 1.24%, with a 95% confidence interval ranging from 0.84 to 1.76%. Due to the use of non-parametric bootstrapping to sample the mean confidence intervals for complex data distributions, the mean confidence intervals on these results are symmetrical, yet indicative of the high variability in the raw data.
- The top contributors to CO_2 and CH_4 emissions are combustion exhaust and other venting from compressor systems. Compressor systems are prevalent in all supply chain stages, so compressor emissions are key emission drivers in all supply chain stages.

Life Cycle Analysis of Natural Gas Extraction and Power Generation, April 19, 2019. The report was prepared by Energy Sector Planning and Analysis (ESPA) for the United States Department of Energy (DOE), National Energy Technology Laboratory (NETL).

Quantified Emissions - Upstream

FY 21-22 Usage	6,675,907 therms
	X
Upstream Emissions Methodology	0.001988 mt CO_2 per Therm
	=
Upstream Emissions Total	13,272 mt CO_2e



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Existing Emissions Reductions Programs

Under the CARB Cap-and-Trade program (CTP), PG&E currently covers CO_2 emissions for ***metered*** customer usage for "non-covered" entities, including ABAG POWER's
- Does not cover fugitive natural gas for the distribution system or upstream

To meet compliance obligations under CTP, CARB permits the use of:
1. Allowance allocations
2. Offset Projects
   - Livestock
   - Mine Methane Capture
   - Ozone Depleting Substances
   - Rice Cultivation
   - Forest

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Recommended Framework

Annually, ABAG POWER staff will calculate the portfolio's emissions from three sources:

1. ***Metered usage emissions*** using the widely accepted CARB rate of 0.005302 mt CO_2 per Therm
2. ***Distribution-based emissions*** using PG&E's applicable shrinkage factor, then applying CARB's rate of 0.005302 mt CO_2 per Therm and 25x CH_4 equivalency (applied to fugitive)
3. ***Upstream emissions*** (producing, processing, storing, and transporting natural gas on the transmission system) using DOE's rate of 0.001988 mt CO_2 per Therm

Quantified Emissions by Source

	Decision Matrix - Annual mt CO_2 & Cost			
	mt CO_2	\$15 per mt CO_2	\$25 per mt CO_2	\$35 per mt CO_2
Metered Usage Annual Cost	35,396	\$530,935	\$884,892	\$1,238,848
Estimated Cost (\$/MMBTU)	35,396	\$0.7959	\$1.3265	\$1.8571
Distribution Annual Cost	11,280	\$169,208	\$282,013	\$394,819
Cost Adder (\$/MMBTU)	11,280	\$0.2492	\$0.4153	\$0.5814
Low Upstream Annual Cost	9,227	\$138,404	\$230,673	\$322,942
Cost Adder (\$/MMBTU)	9,227	\$0.2038	\$0.3397	\$0.4756
Nominal Upstream Annual Cost	13,272	\$199,076	\$331,793	\$464,510
Cost Adder (\$/MMBTU)	13,272	\$0.2932	\$0.4886	\$0.6841
High Upstream Annual Cost	20,215	\$303,221	\$505,368	\$707,515
Cost Adder (\$/MMBTU)	20,215	\$0.4466	\$0.7443	\$1.0420

Proposed Next Steps

1. Include the estimated cost to offset distribution and upstream emissions (approximately $614,000) in the fiscal year 2023-24 budget
2. Include an emissions profile in the fiscal year 2022-23 true-up using the approved framework, with the intent to offset the emissions during fiscal year 2023-24
3. Identify potential project types and opportunities using the 2021-22 baseline data, and report back in June (informational item) and August (action item)

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Questions / Comments

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