Case Studies - O&G Sector Specialty - CARB Verifier Accreditation Training 2024

The nine case studies, to be covered during the Oil and Gas Course training, are included in this handout. The case study solutions will be covered during the presentation.

The following case studies are included in this handout:

Petroleum and Natural Gas Case Studies

Refinery Case Studies

Hydrogen Case Study

PNG – link to hydrocarbon basins

Case Study #1 - Non-metered Pneumatic Device Vent Emissions

An onshore natural gas transmission compression facility has 5 non-metered continuous low-bleed pneumatic device vents. There are no records establishing the number of hours the vents were operational for the year. The mole fraction of methane in the gas is 0.95.

- Calculate the annual methane emissions in metric tons CO_2e from these devices for 2017 data.
- What are the requirements for determining the mole fraction?
- How does this calculation change for 2019 data?

Case Study #1 - Solution

Non-metered Pneumatic Device Vent Emissions

Use Equation 2 for non-metered continuous low-bleed pneumatic device vents

- For emissions factor, use App. A Table 3 Natural Gas Transmission Compression Low Bleed value of 1.37 scf/hr/component
- 5 devices x 1.37 scf/hr/device x 8760 hour (default) = 60,006 scf Natural Gas

Use Equation 31 to convert scf Natural Gas to scf Methane

- 60,006 scf NG x 0.95 mole fraction = 57,005.7 scf Methane

Use Equation 32 to convert SCF Methane to MT Methane

- 57,005.7 scf Methane x 0.0192 kg/ft^3 x .001 = 1.0945 MT Methane

Convert MT Methane to MT CO_2e

- 1.0945 x 21 = 22.98 MT CO_2e
  For 2021+ data: [1.0945 x 25 = 27.36 MT CO2e]

Mole Fraction Requirements are specified in Equation 31

- Use §95153(s)(2)(C) for onshore natural gas transmission compression systems
- If a continuous gas composition analyzer is installed, use for weighted average annual value
- If no analyzer, then annual samples per §95154(b)

NG emissions rate → volume of NG → volume of methane → mass of methane → mass of CO2e

The calculation for 2019 data must be based on measured vent rates from a temporary meter, or a calibrated bag to collect a volume of gas for a measured period of time and applying that vent rate to that device. Default emission factors would only be allowed if the emissions were reported as de minimis. If reported as de minimis, no metering or annual measurement is required.

Case Study #2 - Wellhead Test Venting and Associated Gas Flaring

An onshore petroleum and natural gas production facility has 10 oil wells and 5 natural gas wells within the same hydrocarbon basin. The oil well production rate is 12 bbl/day with a GOR of 322 scf/bbl. The gas well production rate is 70 Mcf/day. Each oil well was tested for a total of 8 days per year and each gas well was tested for a total of 4 days per year. Assume all gases are vented during all wellhead testing.

- Calculate the volume of Natural Gas vented from wellhead testing.
- What information is missing to calculate vented emissions?
- What procedures would be used if the GOR could not be determined from available data?
- How would the annual emissions be calculated if all of the produced associated gas for the entire year was sent to a thermal incinerator?

Case Study #2 - Solution
Wellhead Test Venting and Associated Gas Flaring

Oil and Gas Well Test Emissions

$$E_{S,n} = Total\ GOR * FR * D \qquad \text{(Eq. 15)}$$

Use § 95153(j)(3) Equation 15 for Oil Well Testing Emissions

- 322 scf/bbl GOR x 12 bbl/day x 8 days x 10 wells = 309,120 scf natural gas
- Calculate the scf Methane and CO_2 using Equation 31 (need CH_4 and CO_2 mole fraction data)
- Calculate the MT Methane and CO_2 using Equation 32
- Calculate the CO_2e

Must have a Total GOR value from each well, or from a cluster of wells with similar GOR values. If GOR cannot be determined from available data, operator must have GOR tested (per Flash Liberation Test in App. B, or other published standard).

$$E_{a,n} = PR * D \qquad \text{(Eq. 16)}$$

Use § 95153(j)(3) and Equation 16 for Gas Well Testing Emissions

- 70 Mcf/day x 4 days x 5 wells = 1,400 Mcf natural gas
- Adjust to STP using Equation 29 (need gas flow temperature and pressure data)
- Calculate the scf Methane and CO_2 using Equation 31 (need CH_4 and CO_2 mole fraction data)
- Calculate the MT Methane and CO_2 using Equation 32
- Calculate the CO_2e

Associated Gas Emissions if Flared

If the associated gas was sent to a thermal incinerator (or flare) use § 95153(l) Equations 18 and 19 (for methane and carbon dioxide), and § 95153(y)(2)(d) Equation 37 (for N_2O) to calculate emissions for the portion of gas sent to the flare.

$$E_{a,CH4} = V_a * X_{CH4} * [(1 - \eta) * Z_L + Z_U] \qquad \text{(Eq. 18)}$$

$$E_{a,CO2} = V_a * X_{CO2} + \sum_{j=1}^{5} (\eta * V_a * Y_j * R_j * Z_L) \qquad \text{(Eq. 19)}$$

Additional data needed includes the operating records for the combustion device, the destruction efficiency (or can use 98% default), the composition of the associated gas sent to the incinerator (mole fraction of CO_2, methane, ethane, propane, butane and pentane+), and the HHV, temperature and pressure of the associated gas.

Where:

$E_{a,CH4}$ = Annual CH_4 emissions from flare stack in cubic feet, under actual conditions.
$E_{a,CO2}$ = Annual CO_2 emissions from flare stack in cubic feet, under actual conditions.
V_a = Volume of gas sent to flare in cubic feet, during the year.
η = Fraction of gas combusted by a burning flare (default is 0.98). For gas sent to an unlit flare, η is zero.
X_{CH4} = Mole fraction of CH_4 in gas to the flare.
Z_L = Fraction of the feed gas sent to a burning flare (equal to $1 - Z_U$).
Z_U = Fraction of the feed gas sent to an unlit flare determined by engineering estimate and process knowledge based on best available data and operating records.
X_{CO2} = Mole fraction of CO_2 in gas to the flare.
Y_j = Mole fraction of gas hydrocarbon constituents j (such as methane, ethane, propane, and pentanes-plus).
R_j = Number of carbon atoms in the gas j: 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes-plus.

$$Mass_{N2O} = (1\ x\ 10^{-3}) * Fuel * HHV * EF \qquad \text{(Eq. 37)}$$

Where:

$Mass_{N2O}$ = Annual N_2O emissions from the combustion of a particular type of fuel (metric tons N_2O).
Fuel = Mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).
HHV = Use either a weighted average of measurements of HHV or a default value of 1.235×10^{-3} MMBtu/scf for HHV.
EF = Use 1.0×10^{-4} kg N_2O/MMBtu.
1×10^{-3} = Conversion factor from kilograms to metric tons.

Case Study #3 - Gas Compressor Operations and Metering

A large natural gas compressor station moving natural gas from a processing plant through transmission lines has four natural gas fired turbine driven centrifugal compressors. The station does not have CEMS and meters total fuel flow to the turbines. During the site visit, it was noted that the compressors use gas to spin-up (start-up) the turbines, and this spin-up gas is vented.

- What PNG sections of the rule would be used to calculate emissions?
- How would you verify turbine spin-up emissions?

Case Study #3 - Solution
Gas Compressor Operations and Metering

Categorization of the Facility

A gas compressor station moving natural gas from a processing plant through transmission lines falls under § 95150(a)(4) Onshore Natural Gas Transmission Compression industry segment.

Section 95152(e)(1) - (8) lists the following reportable emission sources for this industry segment:

(1) Metered natural gas pneumatic device and pump venting;
(2) Non-metered natural gas pneumatic device venting;
(3) Equipment and pipeline blowdowns;
(4) Transmission storage tanks;
(5) Flare stack or other destruction device emissions;
(6) Centrifugal compressor venting;
(7) Reciprocating compressor venting; and
(8) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

Section 95152(j) states the requirements for reporting stationary combustion sources.

Section 95153(m)(1)(A) states the requirements for reporting emissions from centrifugal compressor start-ups.

Turbine Combustion Emissions

Per §95152(j), the fuel combustion in the turbine is reported using 95115 Stationary Fuel Combustion sources. Note that the fuel used to spin-up the turbines would be subtracted from the total turbine inlet fuel to yield the fuel combusted in the turbines (see turbine spin-up emissions).

Turbine Spin-up Emissions

The fuel used to spin-up the centrifugal turbines leads to vented CH_4 and CO_2 emissions that must be estimated. A record of turbine start-up events, and engineering data on the volume of gas used to spin-up the turbines should be obtained. Section 95153(m) provides the calculation method for spin-up emissions. The vented spin-up emissions can significantly increase the total MT CO_2e emissions compared to when all the turbine inlet gas is combusted.

OPTIONAL:
Other Emissions Sources

Site schematics and equipment lists should be used to determine the number of each type of emitting equipment (e.g. pneumatic devices, transmission condensate storage tanks, pressure relief values, etc.) associated with the facility. Emissions from each type of component are calculated using § 95153.

Case Study #4- Meter and Instrumentation Data Analysis

The GHG Monitoring Plan and refinery fuel gas flow data files were provided in advance of the site visit. Using the example fuel flow data table below, what questions would you ask about the data and what additional evidence would you request?

Consider the following issues:

- Data completeness
- Data inconsistencies
- Bad or suspect data
- Process offline or instrumentation failure
- Calibration adjustments

Example data set.

Refinery ABC			STP= 68F			
Meter Tag #	ARB 2013 FCCU					
Units	mmscft					
	January	February	March	April	May	June
1	0.24	0.03	113.75	97.85	23.65	43.85
2	0.24	23.60	113.66	93.80	23.60	42.41
3	0.23	23.38	113.80	91.59	23.38	42.15
4	0.23	23.92	113.76	93.35	23.92	43.51
5	0.23	22.55	13.73	102.93	22.55	43.47
6	0.23	18.85	13.76	93.73	18.85	38.96
7	0.22	16.03	13.74	95.61	16.03	33.49
8	0.23	11.76	13.69	96.96	11.76	27.35
9	0.22	9.70	13.78	104.85	9.70	22.17
10	0.22	0.03	13.73	109.00	10.79	25.34
11	0.22	0.03	13.76	114.00	15.55	33.55
12	0.11	0.03	13.64	112.00	19.73	39.94
13	0.00	0.02	13.51	110.00	22.65	44.45
14		0.02	13.69	114.00	24.25	45.83
15		0.02	13.62	114.00	22.80	
16		0.02	13.62	114.00	19.38	
17		0.02	13.65	114.00	0.02	31.16
18		0.02	13.71	111.25	0.02	
19		0.02	13.75	111.11	0.02	
20		0.02	13.76	106.74	0.02	30.32
21		0.02	13.74	104.76	0.02	26.28
22	55.20	0.02	-13.71	107.71	0.02	27.11
23	107.67	107.67	0.00	107.67	0.02	28.56
24	109.89	109.89	-13.52	109.89	13.31	27.78
25	111.59	111.59	-13.33	111.59	13.55	27.89
26	110.07	110.07	-1.99	110.07	13.84	29.33
27	112.59	112.59	-0.30	112.59	13.18	28.10
28	110.81	110.81	-0.30	110.81	13.59	28.52
29	113.30	113.30	-0.46	113.30	14.63	29.35
30	107.73	107.73	133.50	107.73	14.00	28.37
31	109.52	109.52	133.50	109.52	14.56	29.58
TOTAL	**1051.00**	**1143.25**	**911.22**	**3306.42**	**419.37**	**898.85**

Case Study #4 - Solution
Meter and Instrumentation Data Analysis

A review of the example data set reveals the following possible issues that should be explored further:

(A) Missing data
(B) Data on non-existent days
(C) Exact data match - suspect data
(D) Negative data
(E) Possible recalibration
(F) Rounded data - may be hand entered
(G) Significant drop or change in data
(H) Operational range issue
(I) Meter malfunction

(H) *OVERALL DATA SET*

Refinery ABC STP= 68F
Meter Tag # ARB 2013
Units: mmscft

DAY OR MEASUREMENT	MONTH					
	January	February	March	April	May (G)	June
1	0.24	0.03	113.75	97.85	23.65	43.85
2	0.24	23.60	113.66	93.80	23.60	42.41
3	0.23	23.38	113.80	91.59	23.38	42.15
4	0.23	23.92	113.76 (E)	93.35	23.92	43.51
5	0.23	22.55	13.73	102.93	22.55	43.47
6	0.23	18.85	13.76	93.73	18.85	38.96
7	0.22	16.03	13.74	95.61	16.03	33.49
8	0.23	11.76	13.69	96.96	11.76	27.35
9	0.22	9.70	13.78	104.85	9.70	22.17
10	0.22	0.03	13.73	109.00 (F)	10.79	25.34
11	0.22	0.03	13.76	114.00	15.55	33.55
12	0.11	0.03	13.64	112.00	19.73	39.94
13	0.00	0.02	13.51	110.00	22.65	44.45
14	(A)	0.02	13.69	114.00	24.25	45.83
15		0.02	13.62	114.00	22.80	
16		0.02	13.62	114.00	19.38	
17		0.02	13.65	114.00	0.02	31.16 (A)
18		0.02	13.71	111.25	0.02	
19		0.02	13.75	111.11	0.02	
20		0.02	13.76	106.74	0.02	30.32
21		0.02	13.74	104.76	0.02	26.28
22	55.20	0.02	-13.71	107.71	0.02	27.11
23	(C) 107.67	107.67	0.00 (D)	107.67	0.02	28.56
24	109.89	109.89	-13.52	109.89	13.31	27.78
25	111.59	111.59	-13.33	111.59	13.55	27.89
26	110.07	110.07	-1.99	110.07	13.84	29.33
27	112.59	112.59	-0.30	112.59	13.18	28.10
28	110.81	110.81	-0.30	110.81	13.59	28.52
29	113.30	113.30	-0.46	113.30	14.63	29.35
30	107.73	107.73	133.50 (I)	107.73	14.00	28.37
31	109.52	109.52	133.50	109.52	14.56	29.58
TOTAL	**1051.00**	**1143.25**	**911.22**	**3306.42**	**419.37**	**[illegible].85**

(B)

(A) MISSING DATA
(B) DATA ON NON-EXISTENT DAYS
(C) EXACT DATA MATCH
(D) NEGATIVE DATA
(E) RECALIBRATION?
(F) ROUNDED OFF DATA - MAYBE HAND ENTERED?
(G) DRAMATIC DROP OFF OR CHANGE STARTING MONTH
(H) DOES UNIT HAVE RANGE TO OPERATE? (E.G. 13-15 --> 115?)
(I) METER MALFUNCTION

Case Study #5 - Refinery Fuel Gas Combustion and Flare Emissions

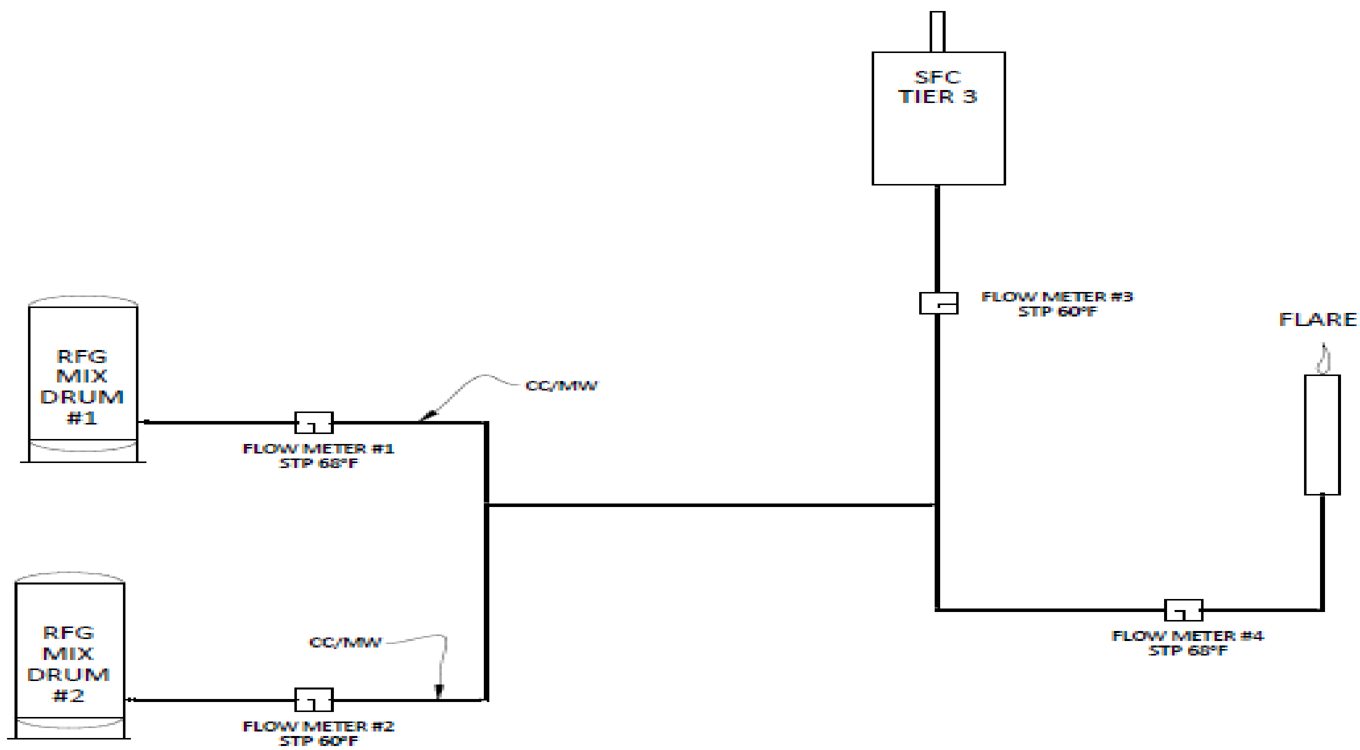
A facility has two refinery fuel gas (RFG) mixing drums each with a flow meter, and known fuel gas carbon content (CC), molecular weight (MW) and heat content (HHV). The RFG (at 60 deg. F) is combusted in a boiler equipped with a RFG flow meter, and RFG also flows to a flare stack with a flow meter (at 68 deg. F).

The facility reports 1,375 MMscf/yr RFG combined for the two mixing drum meters. The boiler RFG flow is reported at 1,110 MMscf/yr and the flow to the flare is reported at 215 MMscf/yr.

MW= 20 kg/kg-mole daily averages; Carbon Content CC= 0.60 kg C/kg RFG, RFG HHV at combined mixing drums is 550 Btu/scf (monthly average)

- Calculate the CO_2 emissions from each process.
- Calculate the CO_2 emissions if the flare flow line had a RFG recovery system with a 96.7% recovery rate.
- What concerns would you address with the reported data?

See schematic below.



Case Study #5 – Solution
Refinery Fuel Gas Combustion and Flare Emissions

The boiler RFG meter is calibrated to STP @ 60 deg. F., the flare RFG meter is calibrated to STP @ 68 deg. F.

The MW and CC are given and used a daily arithmetic average.

CC and MW must either be collected downstream from where RFG mix 1 and mix 2 are combined, or the CC and MW of the mixture must be determined using the weighted average of the CC and MW of RFG mix 1 and mix 2:

[(Flow1 x CC1) + (Flow2 x CC2)]/(Flow1 + Flow2) = CC of the mixture used to calculate combustion and flare emissions

Boiler emissions: Equation C-5 with MVC of 836.6 scf/kg-mole

= 44/12 x 1,110 MMscf x 1,000,000 scf/ MMscf x 1 /836.6 scf/kg-mole x 20 kg/kg-mole x 0.60kgC/kg of fuel x 0.001 MT/kg = 58,379.2 MT/yr

Flare emissions: Y-1a with MVC of 849.5 scf/kg-mole

= 0.98 x 0.001 x 44/12 x 215 MMscf x 1,000,000 scf/MMscf x 1 /849.5 scf/kg-mole x 20 kg/kg-mole x 0.60 kg C/kg of fuel = 10,913.24 MT/yr

Flare recovery system capture rate of 96.7%

= 10,913.24MT/yr x (1 - 0.967) = 360.14 MT/yr

What questions to ask:

- RFG metering does not reconcile (any other user of RFG)?
- Why are meters calibrated at different STP conditions?
- Why was Y-1a selected as most appropriate equation (how does HHV Equation Y2 compare)?
- Would you complete a secondary calculation using HHV?
- Any start-up, shut-down or malfunction conditions per §95113(d)?

Case Study #6 - Fluid Catalytic Cracking Unit

A fluid catalytic cracking unit (<10,000 bbl/day) sends flue gas to a boiler. The boiler also receives supplemental fuel from natural gas. The stack for the combined emissions does not have a CEMS. The refinery monitors the volume, CO_2 and CO concentrations of the exhaust gas from the FCCU. The exhaust volume from the FCCU for one hour is 10 MMscf at 68 deg. F, the average $\%CO_2$ is 20%, and the average %CO is 2%.

- Determine the method for calculating emissions from the FCCU, and calculate the CO_2 emissions for one hour.
- How should the emissions from the supplemental fuel be calculated and reported?
- How would the calculations be done differently if there was CEMS on the common stack, and the FCCU exhaust was not separately monitored?

Case Study #6 - Solution
Fluid Catalytic Cracking Unit

The appropriate methods are from §98.253(c). Equation Y-8 is not allowed under the MRR. If there is no CEMS, equation Y-6 is used. In the example, the volume, %CO_2 and %CO values are measured. Use Equation Y-6.

10,000,000 scf x (20+2)/100 x 44kg/kg-mole x 1/849.5 scf/kg-mole x 0.001 = 113.9 MT CO_2 (one hour)

Hourly results for the data year are summed to report annual emissions from the unit.

In the example, if there was no CEMS, and the emissions from the FCCU were reported as above, the emissions from the supplementary fuel would be calculated separately according to Subpart C.

If there was a CEMS on the shared exhaust stack, and the exhaust from the FCCU flue gas was not measured, the emissions from the supplemental fuels would need to be calculated and reported under Subpart C (stationary fuel combustion) and this value would be subtracted from the CEMS emissions to calculate and report the emissions from the FCCU.

Case Study #7 - Sulfur Recovery Unit

Calculate the CO_2 from a Claus sulfur recovery unit, assuming 1,500 MMscf per year (68 deg. F) of sour gas feed, gas composition unavailable, and default mole fraction of carbon, without CEMS.

After completing the above calculation, it is discovered that a portion of the tail gas is recycled to the front of the sulfur recovery plant (upstream of meter) and that engineering estimates are used to perform the necessary correction.

The reporting entity has reported 16,356 $MTCO_2$ for this unit. Do you consider this to be a reasonable estimate? Why or why not?

Case Study #7 - Solution
Sulfur Recovery Unit

Part 98.253(f): Equation Y-12:

CO_2 = *1,500,000,000 scf x 44g/kg-mole x 1/849.5 scf/kg-mole x 0.20 x 0.001 MT/kg = 15,538.55* $MTCO_2$

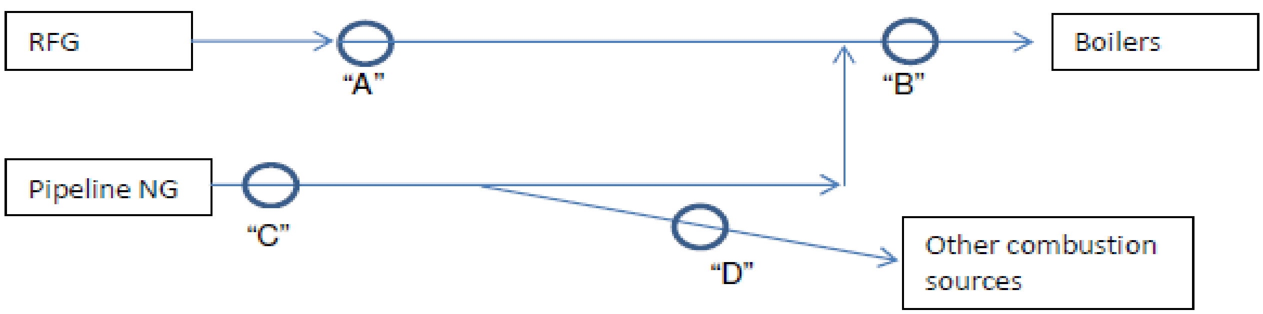
Reported value does not appear to reasonably account for tail gas recycling. The emissions, corrected for the recycling of tail gas, should be lower than the uncorrected value.

Tail gas carbon emissions should not be double-counted. If the carbon in the recycled tail gas is not "backed out" of the calculation, the result will be over-estimated.

Case Study #8 - Multiple Fuel Gases and Metering

See diagram below.

- Identify the error in the calculation, and correctly calculate CO_2 emissions from RFG only - (assumed STP 68 deg. F)
- Calculate CO_2 emissions from natural gas
- Sum the emissions from RFG and natural gas, and compare with the reported total emissions
  - Does this represent a material misstatement?
  - Would the error be a positive or negative value?



At point "A", the refinery measures weighted annual average CC (0.60) and MW (20 kg/kg-mole) of refinery fuel gas. The volume measurement is not +/-5% accurate and is not used.

Point "B" measures 1,500 MMscf of mixed refinery and natural gas.

At point "C", 2,000 MMscf of pipeline natural gas is purchased at 1,020 Btu/scf annual weighted average HHV.

At point "D", 1,500 MMscf is measured.

The refinery performs the following calculations:

For CO_2 emissions from boilers using equation C-5:

44/12 x 1500 MMscf x 1,000,000 scf/1MMscf x 1 kg-mole/849.5 scf x 20 kg/kg-mole x 0.60 kg/kg of fuel x 0.001 MT/kg = 77,693 MT CO_2

For CO_2 emissions from "other combustion sources" using equation C-2a:

1,500 MMscf x 1,020 Btu/scf x 53.02 kg CO2/MMBtu x .001 MT/kg = 81,120.6 MT CO_2

Total: 158,814 $MTCO_2$

Case Study #8 - Solution
Multiple Fuel Gases and Metering

Report's calculation is not appropriate because carbon content of RFG is applied to volume of combined pipeline NG and RFG. The reporter would need to back out the volume of pipeline natural gas (2000-1500 = 500 MMscf), which leaves 1,000 MMscf for the RFG.

Calculate emissions from RFG using CC and MW from point "A" using equation C-5:

44/12 x 1,000 MMscf x 1,000,000 scf/1MMscf x 1 /849.5 scf x 20 kg/kg-mole x 0.60 kg C/kg of fuel x 0.001 metric tons/kg = 51,795.17 $MTCO_2$

Next, calculate emissions from pipeline natural gas combustion using the upstream meter (2,000 MMscf using the common pipe designation). Separately calculate emissions from the 2 sources (1,500 MMscf to other combustion sources, and 500 MMscf to the boiler) using a Tier 2 method (but it is simpler to calculate using the single upstream meter):

2,000 MMscf x 1,020 Btu/scf x 53.02 kg CO_2/MMBtu x .001 metric tons/kg =
108,160.8 $MTCO_2$

Total: 159,956 $MTCO_2$

Percent error is -0.7%

100 x (158,814-159,956) / 158,814

Note that the error is calculated as 100 x (Reported Value - Verifier Value) / Reported Value
So a negative error means the value was under-reported.

Case Study #9 - Hydrogen Plant Weighted Average Carbon Content and Emissions

A hydrogen plant was offline for the start of the year, and begins operations January 16. For the month of January, the operator uses Equation P-1 to calculate CO2 process emissions, but incorrectly uses the arithmetic average of 0.659 for the measured carbon content of the refinery fuel gas feedstock. The weighted average molecular weight for the RFG is 26.18 kg/kg-mole and the volume of RFG for the month is 45,000,000 scf. The plant reports 3,353 MT of CO_2 emissions for the month of January.

- Using the data in the table below, calculate the weighted average for carbon content.
- Calculate the correct CO_2 emissions using Equation P-1, and determine the % error.
- Does this represent a material misstatement?
- Note that one measurement for carbon content is missing. Has the facility used the appropriate missing data provisions?

Date in January	RFG Carbon Content (kg C/kg gas)	MW (kg ga/kg-mol gas)	RFG Mass (kg) (= scf x MW/849.5)	Carbon Mass (= CC x Kg RFG)	RFG Volume (scf)
15-Jan	Plant offline, no emissions				
16	0.75	27	95,350	71,513	3,000,000
17	0.65	26	61,212	39,788	2,000,000
18	0.6	25	58,858	35,315	2,000,000
19	0.6	25	58,858	35,315	2,000,000
20	0.65 missing data substituted using best available estimate	26	91,819	59,682	3,000,000
21	0.7	27	127,134	88,994	4,000,000
22	0.75	27	95,350	71,513	3,000,000
23	0.65	26	61,212	39,788	2,000,000
24	0.6	25	58,858	35,315	2,000,000
25	0.65	26	91,819	59,682	3,000,000
26	0.7	27	127,134	88,994	4,000,000
27	0.75	27	127,134	95,350	4,000,000
28	0.65	26	91,819	59,682	3,000,000
29	0.6	25	58,858	35,315	2,000,000
30	0.65	26	91,819	59,682	3,000,000
31	0.6	25	88,287	52,972	3,000,000
	Arithemtic ave. = 0.659	Weighted ave. = 26.18	Total = 1,385,521	Total = 928,899	Total = 45,000,000

Case Study #9 - Solution
Hydrogen Plant Weighted Average Carbon Content and Emissions

- Weighted average CC
  - 928,899/1,385,521 = 0.670 (§ 95114(f)(2))
- Emissions calculation
  - Incorrect = 44/12 x 45,000,000 x *0.659* x 26.18/849.5 x 0.001 = 3,351 MT CO_2
  - Correct = 44/12 x 45,000,000 x *0.670* x 26.18/849.5 x 0.001 = 3,407 MT CO_2
  - Error = 100 x (3,351 – 3,407)/ 3,351 = -1.67% error
  - No material misstatement (but a correctable error)

- Missing data
  - 1 missing day/16 total days = 6.25% missing data
  - Best available estimate is allowed for data substitution
    - For example, estimated using the mean of the measurements taken immediately before and after missing measurement

[Note that, during an actual verification, the amount of missing data and the material misstatement evaluation would be determined using all of the data for the data year. Here we are using a small data set for purposes of demonstration.]