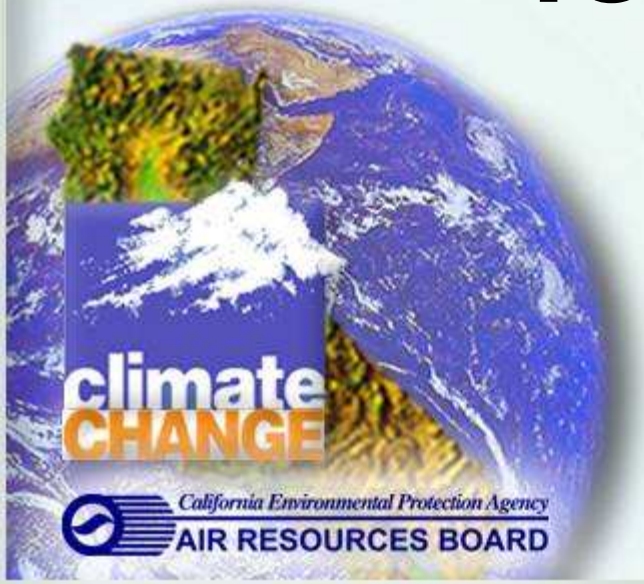
AB 32 and the California Petroleum Refinery Sector

Greenhouse Gas Reporting

Technical Discussion



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Sacramento

Discussion Topics

- Reporting Basics
- Stationary Combustion – Fuels and Gases
- Process Emissions and Data
- Fugitives
- Reporting for Co-generation Facilities
- Verification
- Schedule

Proposed Reporting Basics

- Annual reporting on a facility basis
- Stationary combustion, process, fugitive emissions (direct emissions)
- Purchased energy usage (indirect emissions)
- Mobile sources $\geq$ 25,000 MT (not expected to affect refineries)
- All 6 Kyoto gases -- unless methods not specified in the regulation

Defining the Facility

- Sources of GHGs on contiguous or adjacent properties
- Common operational control
  - Authority to implement environmental, health, safety rules
- A single major industrial source grouping (SIC/NAIC code)

Potential for Broader Scope

- Market Advisory Committee draft report recommends broadest practical inclusion of sources, including transportation.
- "Mandatory reporting should be instituted as soon as possible for all entities likely to be covered by the program…".
- ARB may need "a system to monitor the amount of carbon sold by refiners and importers in the form of gasoline and transport diesel fuel."
- Should refineries report carbon content of products used in California?

Stationary Combustion CO_2 Emissions
Refinery Derived Fuel

HHV – hourly

ECO2 = F(scf/time) x HHV(Btu/scf) x EF(tonnes C/10^6 Btu) x 44/12

Carbon Content – daily

ECO2 = F(m^3/time) x CF(gmole/m^3) x M(g/gmole) x C(g C/g fuel) x 44/12 x Mt/10^6g

CF calculations will be used calculate the EF used in daily HHV emission calculations

ASTM Methods will be applied to HHV, flow rate and CF determinations

Stationary Combustion CH_4 and N_2O Emissions

- Equipment specific emission factors (AP-42, API, IPCC)
  - Refinery Gas – API equipment specific EFs

CO_2 Emission Factors
Natural Gas

HHV (Btu/scf)	Emission Factor (MT/10^9 Btu)	
	CO_2	Carbon
975 – 1,000	53.97	14.73
1,001 – 1,025	52.87	14.43
1,026 – 1,050	53.02	14.47
1,051 – 1,075	53.42	14.58
1,075 – 1,100	53.68	14.65
> 1,100	54.67	14.92

Source: EIA, Documentation for Emissions of Greenhouse Gases in the U.S. 2004, Dec 2006, DOE/EIA-0638(2004)

www.eia.doe.gov/oiaf/1605/ggrpt/documentation/pdf/0638(2004).pdf

Process Emissions

Catalytic Cracking Units (CO_2)

(1) Coke Burn Method

USEPA 40 Part 63 (40CFR63.1564) refineries calculate coke burn rate (Rc)

$$ECO_2 = Rc \times CF \times [44 \text{ mass units of } CO2/12 \text{ Mass units of C}]$$

(2) Air rates and flue gas CO/CO_2 based method

$$ECO_2 = (AR + SOR) \times (FCO_2 + FCO) \times 44/\text{molar conversion factor} \times 525{,}600 \text{ min/yr}$$

CF = coke carbon fraction
AR = air rate to regenerator
SOR = supplemental O_2 rate
FCO_2 = fraction of CO_2 in flue gas
FCO = fraction of CO in flue gas

Process Emissions

Cokers (CO_2)

$$ECO_2 = Crr \times FC \times CO_2/C\ (44/12)$$

Where:

ECO_2 = CO_2 emissions (tonnes/yr)

Crr = cat regeneration rate (tonnes/yr)

FC = weigh fraction carbon on catalyst

Process Emissions

Hydrogen Plant Production (CO_2)

API Preferred Methods – 1) Mass balance or 2) H_2 production rate based H_2 production reaction

$$C_xH(2x+2) + 2xH_2O \rightarrow (3x+1)H_2 + xCO_2$$

1) $ECO_2 = FR \times CF \times 44g\ CO_2/12g\ C$ or

2) $ECO_2 = H_2R \times (x\ mole\ CO_2)/(3x + 1) \times 44/molar\ volume\ conversion$

NOTE: Method 2) does not apply w/ refinery gas where H_2 is a component of the fuel

FR = feedstock rate
CF = carbon fraction (fuel composition)
H_2R = hydrogen production rate
X = stoichiometry derived from feedstock composition

Process Emissions

Hydrogen Plant Production (CO_2)

- **Hydrogen plant feedstocks**
  - NG – HHV and CF w/Btu specific EFs
  - Refinery fuel – HHV hourly, CF daily
  - Fuel mixtures – naphtha – HHV hourly, CF daily
- **Hydrogen production rate (H2R)**
  - process data, hourly, do not use H2R method w/ refinery fuel
- **SMR Low Temperature Shift** – CO_2 desorber and de-aerator vent emissions

Process Emissions

Sulfur Recovery Units (CO_2)

- **Stationary Combustion emissions**
  - Standard methods

- **Process emissions - Crude derived carbon entrained in the SRU process**
  - TGTU flow rate x CF in tail gas
  - ECO_2 = Sulfur production x 0.1374

Source: Atmospheric Emissions Inventories Methodologies in the Petroleum Industry, ARPEL, 1998, pg. 6-39
http://www.arpel.org/en/

Asphalt Blowing (CO_2 and CH_4)

- Stationary Combustion emissions

  Heaters, blowers – standard methodology

- Process emissions
  - Hot petroleum residuum emissions – Emission Factors and Flow Rate
  - Fugitive emissions from storage tanks, material handling operations – Model(s)?
  - Incinerators, thermal destruction devices – combustion fuel and crude derived VOCs

Asphalt Blowing cont'd

- API Method (gas emissions x wt%)
  - AP-42 (1995)
  - 0.3 tonnes emissions/tonne blown asphalt
  - ARPEL (1998)
  - Tank head space vapor composition from 1980 reference

  Calculation assumes no thermal destruction

  CH_4 emitted as CH_4

  Does not calculate emissions for C2+ compounds (20 mole%)

Process Data

Data collection, archiving, and validation

- Process Data
  - Hydrogen production rate
  - Coke burn rate
  - Fuel composition data (HHV and CF)
  - Flow rates
  - SRU Tail Gas flow rates
  - Asphalt production rates

Fugitive Emissions

Storage Tanks (CH_4)

Fugitive CH_4 loss from crude oil storage tanks

- Working
- Breathing
- Flashing Losses

- Effect of wind speed on floating roof tank emissions

- E&P TANK equation of state estimates all three losses
  - Software available from API ($450)

Fugitive Emissions
CH_4

- API – suggests that fugitive emissions are minimal
  - Model and Component based estimation methods
- New optical measurements suggest fugitive emissions may be larger, perhaps approaching 1-2% of total emissions
- Present methods may underestimate emissions

www.arc.ab.ca/ARC-Admin/UploadedDocs/Dial%20Final%20Report%20Nov06.pdf

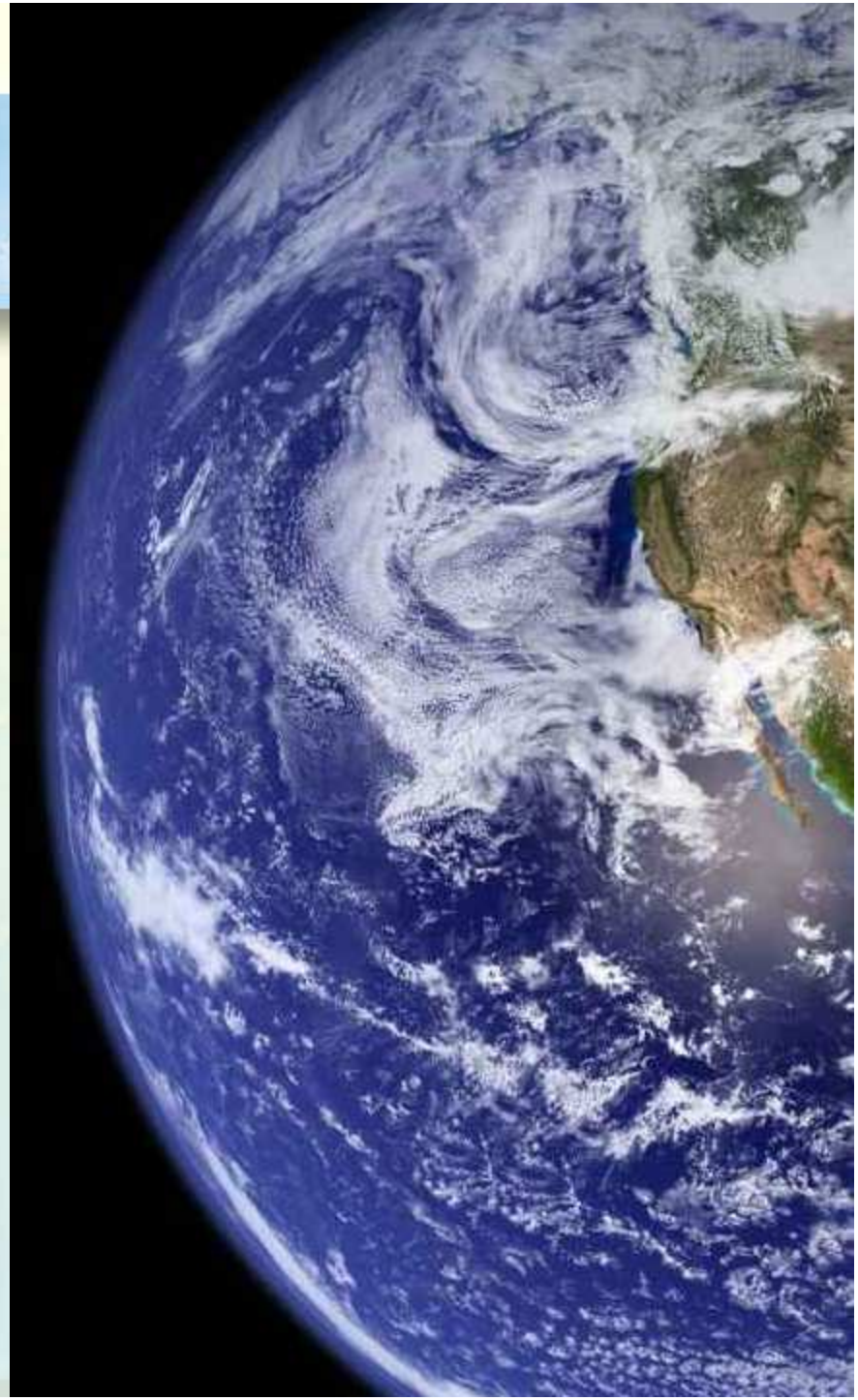
VOC Fugitive Losses: New Monitors, Emission Losses, and Potential Policy Gaps, 2006 International Workshop, EPA
www.emsus.com/downloads/voc_fugitive_losses.pdf

Fugitive Emissions

Flares (CO_2, CH_4, N_2O)

- AQMD Report data used to calculate emissions
  - Assume combustion efficiency (98-99.5%)
  - Conservative assumption concerning NMHC composition

Cogeneration: Proposed Approach



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Cogeneration Facilities in CA

- 917 Total (U.S. EPA data)
- 334 may be subject to reporting (≥1 MW)
  - 201 facilities sell electricity
- 17 Sites at Petroleum Refineries in CA
  - All would be subject to reporting
  - Company with operational control would be responsible
- Reporting Requirements

Cogeneration: Reporting Requirements

- Type of Facility
- Fuel Type and Amount Consumed
- CHP Technology Type(s)
- Total CO_2, CH_4, N_2O
- Total electricity (MWh) output, sold to the grid, sold or provided to other users, and consumed on-site
- Total thermal energy (BTUs) output, usable thermal energy, and BTUs consumed on-site
- Indirect electricity purchases
- Emissions allocated based on energy stream output

Cogeneration: GHG Emissions Allocation

- Stationary Combustion Emissions On-Site Reported as Direct Emissions
- Methods Evaluated
  - Work Potential
  - Energy Content
  - Public Utilities Commission (PUC) Conversion
  - Efficiency
- Considering Two Approaches
  - PUC Conversion Method
  - California Climate Action Registry (Registry) Efficiency Method

PUC Conversion Method: GHG Emissions Allocation

$$\text{Emission Rate} = \frac{\text{Total GHGEmissions}}{\text{Electricity Output (kWh)} + \text{Usable Thermal Energy (kWh)}}$$

Where:

Total GHG Emissions = Metric Tons CO_2e
Electricity Output = Total Produced Annually
Thermal Energy Output = Usable Thermal Energy*

Allocated Emissions:

$\text{Emissions}_{\text{Electricity}}$ = Emission Rate • Electricity Output
$\text{Emissions}_{\text{Thermal Energy}}$ = Total GHG Emissions – $\text{Emissions}_{\text{Electricity}}$

*FERC Definition: Thermal Energy Delivered to a Thermal Host

PUC Conversion Method: Example Calculation

$$\text{Emission Rate} = \frac{\text{Total GHGEmissions}}{\text{Electricity Output (kWh)} + \text{Usable Thermal Energy (kWh)}}$$

Where:

Total GHG Emissions = 435,982 Metric Tons CO_2e
Electricity Output = 1,100,600 MWh
Usable Thermal Energy = 2,710,000 million BTU
Emission Rate = 0.00023 Metric Tons CO_2e/kWh

Allocated Emissions:

Energy Stream	**Metric Tons CO_2e**
Electricity	253,138
Thermal Energy	182,844
Total	435,982

Note: Example calculation uses API Compendium Assumptions & Input Data

Registry Efficiency Method: GHG Emissions Allocation

Thermal Energy	Electricity
$E_H = \frac{H/e_H}{H/e_H + P/e_P} \times E_T$	$E_P = E_T - E_H$

Where:

E_H = Emissions allocated to steam production
H = Total steam (or heat) output (MMBtu)
e_H = Efficiency of steam (or heat) production
P = Total electricity output (MMBtu)
e_P = Efficiency of electricity generation
E_T = Total direct emissions of the CHP System
E_P = Emissions allocated to electricity production

Registry Efficiency Method: Example Calculation

$$E_H = \frac{\frac{3.614\times10^{12}\ \text{BTU}}{0.80}}{\frac{3.614\times10^{12}\ \text{BTU}}{0.80} + \frac{3.755\times10^{12}\ \text{BTU}}{0.35}} \times 435{,}982 \text{ metric tons } CO_2e$$

Where:

E_H = Emissions allocated to steam production

H = 3.614×10^{12} BTU

e_H = 80% (Efficiency of steam production)

P = 3.755×10^{12} BTU

e_P = 35% (Efficiency of electricity generation)

E_T = 435,982 metric tons CO_2e

E_P = Emissions allocated to electricity production

EH = 129,186 metric tons CO_2e

EP = 435,982 – 129,186 = **306,982 metric tons CO_2e**

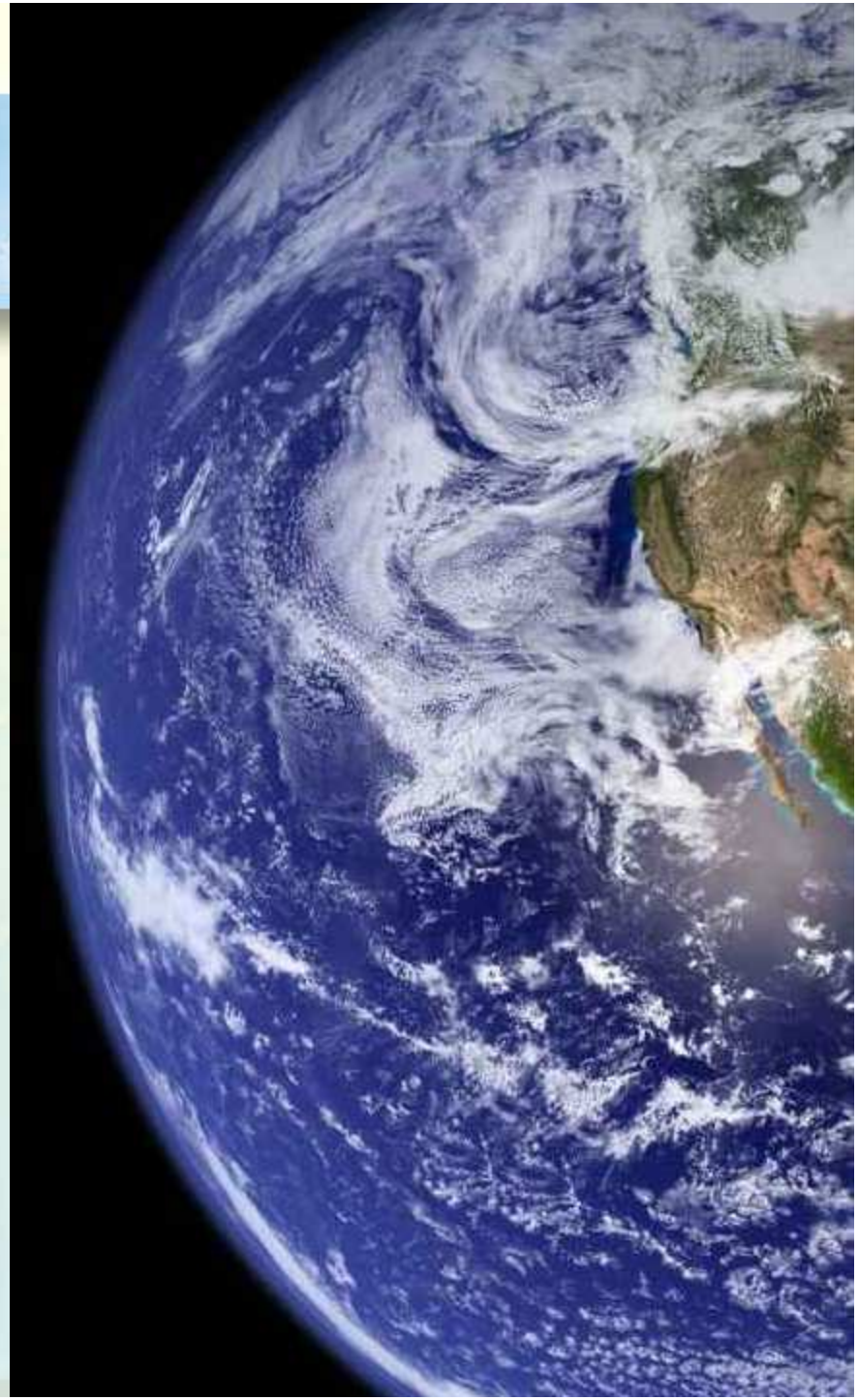
Comparison of Methods: GHG Emissions Allocation

Energy Stream	PUC Conversion Method (Metric Tons CO_2e)	Registry Efficiency Method (Metric Tons CO_2e)
Electricity	253,138	306,796
Thermal Energy	182,844	129,186

Cogeneration: Key Questions

- Should ARB adopt the PUC Conversion Method or the Registry's Efficiency Method?
- Do cogeneration facilities collect data on actual thermal energy and electricity production efficiency values?
- Are there any recommendations for ARB to adopt another method to allocate GHG emissions?
- Other comments?

Verification: Initial Concepts



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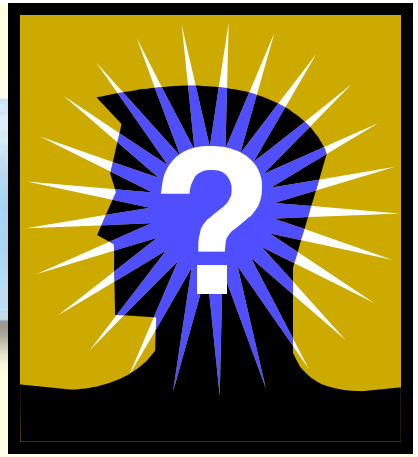
Why Verification?



- AB 32 requires it
- Expected under international standards
- Experience with voluntary reporting shows the need
- Complexity of emissions estimation
- Critical for credibility of program

Verification: Initial Proposal

- Require annual third-party verification for refineries, utilities, and power plants and co-generation facilities selling power to the grid or other users
- Require triennial third-party verification for cement plants and other stationary combustion sources ≥ 25,000 tons CO2
- Require annual third-party verification for anyone entering a future market

Third Party Verification

- Consistent with existing standards, including ISO
  - Already required for CCAR members
- Verifiers to be trained under ARB approved curriculum
  - Demonstrated expertise
  - Consistency in verification

Regulation to Specify

- Core GHG data verification requirements
- Accreditation requirements for verifiers
- Conflict-of-interest limitations
- ARB oversight

Verification Activities

- Identify sources and review data management systems
- Focus on most significant and uncertain sources
- Differences exceeding 5 percent considered significant
- Detailed verification report to facility and ARB

Reporting and Verification Timing

- Power Plants & Co-generators selling energy to other users
  - Emissions reports due by April 1
  - Verification complete by July 31
- Utilities, Refineries, Cement Plants and other stationary combustion sources
  - Emissions reports due by September 1
  - Verification complete by December 31

Accreditation

- ARB to specify requirements necessary to become verifier
- Propose following fairly stringent international and CCAR approaches

Conflict of Interest

- Term Limit
  - Verifiers to be changed after 3 years of conducting verification activities
  - Allowed to resume with client after 1 year off cycle for verification
- Conflict of Interest Policy
  - Must agree not to act on behalf of reporting facility as both consultant and verifier concurrently or within any 3 year period

Verification Oversight

- ARB staff responsible for enforcing regulation
- Verification process will assist efforts to enforce compliance
- Targeted review of submitted data and verifiers

Schedule

- CCAR Discussion Paper
  - Available for comment June 29, 2007 (tentative)
- Continued discussions with ARB staff working on regulatory language
  - Additional technical team meetings needed?
- Regulation Workshop
  - August 9, 2007

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www.arb.ca.gov/cc/cc.htm