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New Air Quality Rules Challenge Oil & Natural Gas Industry

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On July 28, 2011, the EPA Administrator signed a suite of proposed new air regulations affecting both the Production/Processing and Transmission/Storage sectors of the oil and natural gas industry. The proposed rules mandate the use of emission controls as well as work practices through two different air regulatory programs – New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP).

Promulgation of the proposed rules will result in new control equipment requirements as well as increased and potentially burdensome monitoring, recordkeeping, and reporting requirements for owners, operators, contractors, and vendors. EPA has been granted an extension of the final rule promulgation date to April 3, 2012. This leaves very little time for EPA to fully review and consider the extensive industry comments that are expected on the proposed rules. Furthermore, the proposed NSPS will apply to affected facilities constructed, reconstructed, or modified after August 23, 2011. At a minimum, affected sources should ensure the following in preparation for the rule:

- Review and analyze the final published rules, which are expected to differ greatly from the proposed rules
- Inventory all existing facilities, equipment, and operational characteristics to establish a basis for determining applicability of any new, modified, or reconstructed emission sources
- Train staff on operational, monitoring, recordkeeping, and reporting requirements
- Budget for increased costs associated with installation of control equipment, more stringent maintenance and replacement schedules, and resources to handle increased monitoring, recordkeeping, and reporting requirements
- Acquire control equipment from vendors

The proposed NSPS and proposed amended NESHAP are highlighted in the following sections, along with the anticipated impacts of the proposed regulations.

Proposed NSPS 40 CFR Part 60, Subpart OOOO

EPA has proposed new standards under NSPS Subpart OOOO: *Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution* to regulate emissions of volatile organic compounds (VOCs) and sulfur dioxide (SO_2) from the oil and natural gas industry.

The standards for onshore natural gas processing plants, currently found in NSPS Subpart KKK: *Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants* and NSPS Subpart LLL: *Standards of Performance for Onshore Natural Gas Processing: SO_2 Emissions*, are proposed to be revised and consolidated into the new Subpart OOOO. The onshore natural gas processing plants standards consolidated under NSPS Subpart OOOO will apply only to newly affected sources. EPA proposes to modify the existing NSPS Subparts KKK and LLL to limit their applicability only to affected facilities already subject to those subparts.

The new NSPS Subpart OOOO will include, for the first time, federal emissions and work practice standards for completions of hydraulically fractured gas wells, pneumatic devices, compressors, and tanks newly constructed, modified, or reconstructed after August 23, 2011 and located anywhere in the natural gas system between the wellhead and the city gate. There is great uncertainty surrounding how owners and operators will comply for affected emissions sources that are new/modified/reconstructed before the rule is finalized. For example, if an owner/operator installs a high-bleed pneumatic controller between now and the final rule promulgation date of April 3, 2012, will they have to replace it with a low-bleed controller at the time the rule is finalized?

Equipment Leaks

Currently, compressors and equipment components at onshore natural gas processing plants are regulated under NSPS Subpart KKK, which refers to the leak detection and repair (LDAR) program requirements of NSPS Subpart VV: *Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006.*

EPA proposes to require newly constructed, modified, or reconstructed facilities at onshore natural gas processing plants to comply with NSPS Subpart VVa: *Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006*. The Subpart VVa LDAR program is more stringent than Subpart VV, with lower component leak threshold definitions and more frequent monitoring. For example, Subpart VVa lowers the leak definition for valves from 10,000 parts per million (ppm) to 500 ppm. Additionally, Subpart VVa requires monitoring of connectors, which will be a new requirement for onshore natural gas processing plants. It should be noted that EPA has specifically exempted equipment that is not located at gas processing plants from the equipment leak VOC provisions of the rule.

Sulfur Recovery Units

Currently, sulfur recovery units at onshore natural gas processing plants are regulated under NSPS Subpart LLL.

EPA proposes to increase the maximum initial and continuous efficiency from 99.8% to 99.9% for newly constructed, modified, or reconstructed facilities with sulfur feed rates greater than 5 long tons per day and hydrogen sulfide (H_2S) content greater than or equal to 50%. No changes are proposed for facilities with sulfur feed rates less than 5 long tons per day and H_2S content less than 50%.

Hydraulic Fracturing

Hydraulically fractured well completions on non-exploratory wells would be required to employ "green" completion techniques and/or pit-flaring for both newly fractured wells and existing wells where re-fracturing is performed. Green completions involve installing special equipment that captures and separates gas and liquid hydrocarbons that can then be treated and sold. This equipment may include tanks, gas-liquid-sand separator traps, and gas dehydration. Venting is proposed as an alternative only when pit-flaring poses a safety hazard, when the flowback gas contains high concentrations of nitrogen or carbon dioxide, or when other technical barriers exist.

Fractured exploratory and delineation wells are generally not within proximity to existing gathering lines. Therefore, EPA is proposing the use of pit-flaring for these wells. Again, venting is proposed as an alternative only when pit-flaring is deemed a safety hazard or when flowback gas is noncombustible.

Green completions have been used voluntarily by companies in states such as Wyoming, Colorado, and Utah. However, their technical and economic feasibility is still being evaluated.

Many exploration and production companies question EPA's proposal to apply a "one-size-fits-all" approach to controlling hydraulic fracturing, given the wide range of operations and gas VOC contents across the country.

EPA has determined that VOC emissions from wellheads during production operations are very small, and therefore, is not proposing any controls during these operations.

Pneumatic Devices

EPA proposes to regulate each newly installed pneumatic device at processing plants, production sites, and other natural gas facilities. Pneumatic devices can be categorized as "high-bleed," "low-bleed," and "no-bleed."

- ***High-bleed –*** a device that releases more than 6 standard cubic feet per hour (6 scfh) of gas
- ***Low-bleed –*** a device that releases less than or equal to 6 scfh of gas
- ***No-bleed –*** a device that uses a power source other than pressurized natural gas, such as compressed instrument air, and therefore releases no gas

EPA proposes that natural gas processing plants would be subject to a zero VOC emission standard by installing only no-bleed (or non-gas driven) controllers. No-bleed controllers require an existing electrical service to power an instrument air compressor. Therefore, EPA is proposing no-bleed controller installation at processing plants. At facilities other than natural gas processing plants, where electric power is not readily available, EPA is proposing the installation of low-bleed controllers.

The proposed regulations exempt devices requiring high-bleed controllers for specific reasons, including operational requirements and safety concerns due to their actuation response time or other operating characteristics.

Compressors

EPA proposes to regulate both centrifugal and reciprocating compressors located anywhere between the wellhead and the city gate as VOC emission sources. Each newly constructed and replaced compressor would be an affected unit and would be subject to the proposed requirements.

As proposed, centrifugal compressors must be equipped with dry seal systems, as opposed to wet seal systems. EPA notes that it may allow wet seals if vented to closed vent systems and control devices.

Reciprocating compressors would need to meet operational standards, including the replacement of the rod packing every 26,000 hours of use. This would require monitoring of the hours of operation for each affected compressor. However, EPA is seeking comment on a leak threshold as a basis for rod packing replacement and the appropriateness of a fixed replacement frequency.

Storage Tanks

EPA proposes to regulate new and modified storage vessels with condensate throughput ≥ 1 barrel (bbl) per day or crude oil throughput ≥ 20 bbl per day. These tanks would be required to meet a 95% control efficiency using a vapor recovery unit (VRU) or a flare to control working, breathing, and flashing losses.

EPA is not proposing any controls or operational standards for storage vessels with condensate throughput < 1 bbl per day or crude oil throughput < 20 bbl per day.

Several companies are concerned with the low condensate throughput threshold, given the wide range of liquid VOC contents across the country. Additionally, there is a concern that vendors will not be able to meet the increased demand of control equipment installations that will be required, which could result in facilities operating out of compliance until control equipment becomes available.

Recordkeeping and Reporting Requirements
EPA is proposing a number of new and potentially burdensome recordkeeping and reporting requirements for emission sources affected under NSPS Subpart OOOO, such as:

- Construction, startup, and modification notifications
- 30-day notification prior to each well completion
- Records documenting full compliance with all applicable NSPS Subpart OOOO standards
- Annual or semi-annual reports, depending on the emission source type
- Annual compliance certifications

Staff will need training on new recordkeeping and reporting requirements. Furthermore, many companies may not have the environmental management software needed to track the associated data for each affected emission source.

Proposed Amendments to NESHAP 40 CFR Part 63, Subparts HH and HHH

Amendments to the two natural gas industry NESHAPs (Subpart HH: *National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities* and Subpart HHH: *National Emission Standards for Hazardous Air Pollutants From Natural Gas Transmission and Storage Facilities)* are proposed as a result of EPA's periodic residual risk review. The proposed rule amendments would affect equipment not previously subject to NESHAP such as small dehydrators in both sectors as well as certain storage vessels in the production sector. A number of other updates are proposed relating to the compliance demonstration requirements. EPA is proposing to amend the standards for major sources of HAPs but not for area sources of HAPs.

In both the production and transmission/storage sectors, small dehydrators were previously exempt from the rules. EPA is proposing to remove the 1 tpy benzene alternative compliance option for major sources. Table 1 below, shows the proposed changes for small dehydrators in each NESHAP Subpart.

Currently, NESHAP Subpart HH regulates HAP emissions from storage vessels with the potential to flash. EPA is proposing to require 95% emission reduction to every storage vessel located at major source oil and natural gas production facilities, even those that do not have the potential for flash emissions. In addition, emissions from those tanks must now be counted toward determining the facility's major source status.

In both sectors, EPA is also proposing an alternate compliance option for non-flare combustion devices allowing manufacturers to demonstrate the destruction efficiency for a specific model in lieu of facilities conducting site-specific tests for those specific model devices. In addition, the following compliance related changes are proposed:

- Revisions to the parametric monitoring calibration provisions
- Addition of periodic performance testing where applicable
- Removal of the allowance of a design analysis for all control devices other than condensers
- Removal of the requirement for a minimum residence time for an enclosed combustion device
- Addition of recordkeeping and reporting requirements to document carbon replacement intervals

EPA is also proposing to eliminate the startup, shutdown, malfunction (SSM) exemptions such that the established standards in these two NESHAPs apply at all times. In conjunction with this change, EPA proposes to add a provision for affirmative defense to civil penalties for exceedances of emission limits caused by malfunctions.

Conclusion

The proposed new NSPS and amended NESHAP standards will impact not only owners and operators of oil and natural gas facilities, but contractors and vendors as well. The industry will face increased operational, monitoring, recordkeeping, and reporting requirements, in addition to associated costs. The proposed rules may disproportionately affect small businesses, which will be competing with larger companies for vendor and consultant assistance.

In response to public request, EPA has extended the public comment deadline to November 30, 2011. Additionally, EPA has been granted an extension of the final rule promulgation date to April 3, 2012. These extensions will allow industry to provide additional technical and economic analysis of the proposed rules, and will allow EPA more time to review the extensive comments already made and further expected. However, extension of the final rule promulgation deadline leaves more uncertainty for those sources that become affected under the proposed rule after August 23, 2011 but before April 3, 2012. ❖

Table 1. Proposed Changes to NESHAP for Small Dehydrators

NESHAP Subpart	Emission Limit for Existing Dehydrators (gram BTEX/scm-ppmv)	Emission Limit for New Dehydrators (gram BTEX/scm-ppmv)
HH	1.10×10^{-4}	4.66×10^{-6}
HHH	6.42×10^{-5}	1.10×10^{-5}

Modeling Emissions from Offshore Drilling

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To regulate drilling activities proposed by oil and gas companies in the oil-rich Gulf of Mexico (GOM), governing agencies require the submittal and approval of certain plan documents before drilling activities can be initiated. For drilling activities in the Western GOM, these plans typically consist of one of the following:

- ***EP, or Exploration Plan*** **–** required to conduct exploratory drilling on any offshore lease
- ***DOCD, or Development Operations Coordination Document*** **–** required for development and production drilling activities on any offshore lease in the Western Gulf of Mexico

For the western GOM, the EP and DOCD plans and associated documentation are submitted, reviewed, and approved (or disapproved) by the Bureau of Ocean Energy Management Regulation and Enforcement (BOEMRE), a federal agency regulated under the Department of the Interior. (BOEMRE was previously known as the Minerals Management Service, or MMS). BOEMRE is responsible for overseeing the safe and environmentally responsible development of energy on the Outer Continental Shelf (OCS). Regulations governing the requirements for EP and DOCD plans are codified under Title 30 of the Code of Federal Regulations at 30 CFR Part 250.

An EP or DOCD plan must include air emissions information for the proposed activities. In general, this information includes projected emissions, frequency and duration of emissions, bases for calculations, equipment information, emissions reductions measures (if applicable), and dispersion modeling (if applicable).

Impacts to Air Quality — Importance of Air Dispersion Modeling

Before submitting an EP or DOCD plan to BOEMRE for approval, the applicant must demonstrate that onshore air quality impacts from proposed offshore activities, as compared to the National Ambient Air Quality Standards (NAAQS), will not adversely affect human health or the environment.

Emissions from offshore sources must be quantified using EPA-approved methodologies. These sources include fuel burning sources, such as drilling rigs, generators, flares, and supply vessels as well as sources of fugitive emissions. If these emissions exceed pollutant-specific thresholds, then air dispersion modeling may be required.

Offshore Models

There are several dispersion models available for modeling sources over water, including CALPUFF and OCD (Offshore and Coastal Dispersion Model). BOEMRE typically recommends OCD for the Western GOM because it is usually less time consuming through CALPUFF.

The OCD model was developed by EPA in conjunction with BOEMRE's predecessor agency, the MMS, in the late 1980s, and the model was formally approved for use in January 1988. It is an hourly, steady-state model used to predict the onshore concentration of air pollutants emitted from offshore sources.

As detailed in Table 1, compared to CALPUFF, the OCD model's relatively simpler data processing makes it an efficient model for use in predicting pollutant impacts from offshore sources.

Criteria for Using OCD Modeling

According to BOEMRE, OCD modeling is appropriate when:
(1) the emission source is located in the OCS; and
(2) emissions from the offshore source are greater than certain thresholds based on the

Table 1. Comparison of CALPUFF and OCD

Modeling Software	Summary	Advantage	Disadvantage
CALPUFF	Used for both over-land and over-water dispersion modeling	Sophisticated model	Data pre-processing using CALMET and post-processing using CALPOST are time-consuming
		Includes analysis algorithms for regional haze and acid deposition	Large amount of data involved leads to long run time
OCD	Used for over-water dispersion modeling	Meteorological data is provided by BOEMRE and NOAA and requires no pre- or post-processing	Does not include analysis algorithms for regional haze and acid deposition
		Faster run time	Cannot be used for over-land modeling

following formula used by BOEMRE.

$$E = k^* (D^n)$$

where E = emission threshold, tons/year
D= distance to shore, miles
k and n = pollutant-specific constants

As evidenced by this formula, emission thresholds are based on the distance from the source to the shoreline. The farther the distance to shoreline, the greater the emission threshold will be for a particular pollutant.

EP and DOCD plans typically include the pollutants and thresholds indicated in Table 2:

Table 2. Example Emission Thresholds Based on Varying Distances

Source Distance From Shoreline	Pollutant Thresholds (tons per year)				
	PM	SO_x	NO_x	VOC	CO
20 miles	666	666	666	666	25051
100 miles	3330	3330	3330	3330	73251

Typical offshore activities produce emissions from temporary (well testing, construction and installation) as well as permanent (production) operations. Traditional New Source Review permit modeling requires sources to be modeled in a manner representative of the source's operations that are classified as permanent emissions. However, BOEMRE requires facilities to provide dispersion modeling results that also consider the additional emissions generated during the source's construction phase (classified as temporary emissions). The addition of emissions from the construction phase frequently results in exceedances of modeling thresholds.

Model Input Data

Model input data comprises source-specific data as well as meteorological data. Source-specific data is typically provided by the facility. Meteorological data may be obtained from various sources identified in Table 3.

The following are the principal components for source specific data:

1) ***Location of offshore activities*** - usually available in either Latitude-Longitude coordinates or Universal Transverse Mercator (UTM) coordinates
2) ***Emission rate information for all sources associated with activities at the given location.*** This includes heat input ratings of emissions sources and estimated hours of operation. For the Western GOM this information is typically provided in a BOEMRE-approved AQR format.

3) ***Stack parameters for each source - stack diameter and height, gas exit velocity and temperature, and the stack angle.*** Some sources, such as support vessels, may be modeled as one single source using total combined emissions and conservative default stack parameters.

As detailed in Table 3, the OCD model requires both over-land and over-water meteorological data to determine the potential onshore impacts of the offshore operations. These data include: overland surface characteristics such as surface roughness, and over-water data such as water temperature, over-water air temperature, over-water dew point, over-water wind speed, and over-water wind direction. These data are usually obtained from the offshore buoy closest to the source at three different mixing heights: 300 m, 600 m, and 900 m.

Table 3. OCD Model Input Meteorological Data Requirements

Model Input Data		Data Source
Platform Location	Latitude-Longitude or UTM Coordinates	Facility
Emission Rate Information	Heat Ratings	Facility
	Hours of Operation	
Stack Parameters	Height	Facility
	Diameter	
	Gas Exit Velocity	
	Gas Temperature	
	Dimensions of Nearby Structures	
Over-Water Meteorological Data	Water Temperature	National Data Buoy Center
	Air Temperature	
	Wind Speed and Direction	
	Meteorological Datasets	BOEMRE
Over-Land Meteorological Data	Surface Characteristics	National Oceanic and Atmospheric Administration
	Observation of Key Variables	
	Meteorological Datasets	BOEMRE

Model Setup

After obtaining the required input data, a model is set up by choosing on-shore locations (receptors) at which the OCD model will predict the pollutant concentrations of the modeled emission sources. Receptors are specified on the shoreline and at nearby Class I areas per guidance provided by BOEMRE on receptor placement and spacing.

Model Results

The air quality modeling results are generally submitted in the form of a modeling report to BOEMRE along with the EP or DOCD plans per 30 CFR 250 Subpart B. The report typically includes a comparison of the maximum modeled concentrations with the relevant modeling significance level thresholds for the pollutant-specific averaging periods. If any of the maximum modeled concentrations exceed the corresponding significance levels, additional discussions with BOEMRE may be required.

Offshore platforms and rigs typically comprise combustion units that produce high NO_x emissions when compared to the threshold. Hence, facilities are typically required to model NO_x emissions. For NO_x, the averaging periods under consideration are the annual and the 1-hour standards for NO_2. All modeled NO_x is assumed to be NO_2. Table 4 provides an example of model results.

Table 4. Example OCD Modeling Results

Pollutant	Averaging Period	Maximum Modeled Concentration (µg/m3)	Significance Impact Level (µg/m3)	Significant?
NO_2	Annual	0.12	1	No
	1-hr	18.76	7.5	Yes

Conclusion

Typical offshore activities require modeling for emissions resulting from construction as well as permanent production operations. Although the OCD model does not include algorithms for parameters such as regional haze and acid deposition, it has streamlined data processing and relatively fast model run times. OCD is currently the preferred dispersion model for modeling in the western GOM for EP and DOCD plans submitted to BOEMRE, although CALPUFF may be preferred for some situations. ❖

CSAPR - The New Transport Rule

Not a Very Friendly Ghost

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On August 8, 2011, the core of the new Transport Rule was published in the Federal Register (76 FR 48208), approximately one year after the main rule proposal (75 FR 45210) (covered in the Fall 2010 Environmental Quarterly, *Federal Transport Rule — the "New CAIR" Round 1).* The new rule is known by two names. In press releases and on the EPA website, the rule is referred to as the Cross-State Air Pollution Rule (CSAPR, pronounced like Casper, the friendly ghost). In the regulation itself, EPA instead refers to the Transport Rule (TR), which is the name used in this article.

The rule is long and has emissions allocations based on EPA's many complex assumptions and projections of specific actions that each emissions unit in each state may take, both from an emissions control standpoint and, using EPA's Integrated Planning Model (IPM), also from a utilization perspective. The new TR becomes effective January 1, 2012 (for annual limits), making 2011 the final year of its predecessor CAIR.

Given the complexity of the rule and EPA's ambitious schedule for implementation, it is perhaps not surprising that revisions to the rule are already needed. At the time of publication of this article, EPA has proposed two revisions. The first revision (76 FR 40622) was published prior to the core rule (on July 11) and seeks to add ozone budgets for six states, five of which were included previously for $PM_{2.5}$ in the core rule.[1] The second revision (76 FR 63860) has been recently published (October 14, 2011) and would make numerous corrections to the bases for EPA's allocations for specific units and postpone implementation of the assurance provisions until 2014.[2]

More revisions are anticipated, although the timetable is not clear. In the most recent rule proposal, EPA specifically asked sources to identify any other corrections that are needed. Further, as with the proposed rule, there are many states that contribute to ozone maintenance or nonattainment problems in Baton Rouge or Houston for which the ozone NO_x budget is only a first step, with further reductions planned.[3]

Lastly, the final TR only addresses upwind pollution that "significantly contributes to or interferes with maintenance of" the 1997 ozone NAAQS, the 1997 annual $PM_{2.5}$ NAAQS, and the 2006 24-hr $PM_{2.5}$ NAAQS. Each of these NAAQS are due for an update. The ozone NAAQS was recently re-scheduled

[1] These six states are Iowa, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin.
[2] Proposed rule signed on October 14, 2011.
[3] Alabama, Arkansas, Georgia, Illinois, Indiana, Kentucky, Louisiana, Mississippi, Tennessee and Texas.

for review in 2013, and EPA anticipates a proposed revision to the $PM_{2.5}$ standards in late 2011. EPA designed TR to be applicable to newly issued NAAQS, and new budgets should be expected following the promulgation of new NAAQS. Generally, EPA expects to propose revised TR requirements approximately one year following new NAAQS designations, with a final rule one year later.

Why Address Transport?

Congress has long recognized the potential for transported emissions to impact local air quality, and so called "good neighbor" provisions date to the 1970 Clean Air Act Amendments (CAAA). The original requirement was amended and is now contained in §110(a)(2)(D) of the Act, which requires each state, in its state implementation plan (SIP), to prohibit:

… any source … within the state from emitting any air pollutant in amounts which will contribute significantly to nonattainment in, or interfere with maintenance by, any other state with respect to any [NAAQS]….

Prior to CAIR, EPA regulated transport through the NO_x SIP Call, which addressed emissions contributing to ozone generally east of the Mississippi River. CAIR built upon the approach used in the NO_x SIP Call with both an expanded group of states and more stringent NAAQS (both ozone and $PM_{2.5}$). Despite its grounding in the prior NO_x SIP Call, in an unexpected 2008 ruling, the court found CAIR so fundamentally flawed that it vacated the rule in its entirety. As a result of petitions regarding the lack of any requirement for additional emissions reductions while EPA developed a new rule, the court amended its vacatur of CAIR to a remand, which the current TR seeks to address.

Changes from CAIR

Utilities and some industrial sources have several years of experience with CAIR, and thus CAIR provides a good benchmark for examining the new provisions. At a conceptual level, CAIR and TR are intended to address the same problem. Therefore, in the aggregate, CAIR and TR require many of the same emissions reductions. How the reductions are achieved in CAIR and TR differs substantially.

- ***Regions -*** under CAIR, all states were part of one region. Under TR, NO_x is one region, while SO_2 is divided into two regions. Group 2 states are those that can eliminate their contribution to maintenance or nonattainment based on $500/ton cost effectiveness, and Group 1 states are those that need a higher $2,300/ton cost effectiveness. Group 1 and Group 2 allowances cannot be traded with each other, but can be traded within each group.
- ***Phases -*** like CAIR, TR has two phases, however, the TR phases are based on different underlying assumptions. For TR, EPA first considered the timing of already announced changes in controls, consent orders, and impending state regulations to develop 2012-2013 budgets. Additionally, for Group 1 states, the 2014+ SO_2 budget assumes that some units add scrubbers prior to 2014.
- ***Trading -*** CAIR allowed unlimited interstate trading within the region. The final core TR ***allows very limited*** interstate trading due to the assurance provisions, however, the most recent proposal would allow unlimited trading in 2012-2013 (within each grouping) with limited interstate trading 2014+ after the assurance provisions become effective. TR does allow unlimited intrastate trading.
- ***Banked credits -*** CAIR allowed some carryover of Acid Rain Program (ARP) credits. TR allows none. Any banked CAIR credits are essentially worthless.
- ***Impact on Acid Rain Program credits -*** CAIR devalued ARP credits, but TR has nearly eliminated them. 2009 ARP credits are trading at approximately $1/ton, while 2015 credits are trading at approximately $0.20/ton. States outside of those in TR will see greatly reduced ARP costs.
- ***Credit values -*** few trades have occurred. Averaging bid/ask prices, values for 2012 TR credits are in the $600 range for SO_2 (either group), the $1,400 range for annual NO_x, and the $1,800 range for ozone season NO_x.
- ***Total allowance budgets -*** based on the final core rule and the July 2011 proposal, ozone season budgets are higher under TR than CAIR, while annual budgets are lower under TR than CAIR. However, all TR budgets are within approximately 15% of overall CAIR values.
- ***Non-electrical generating units (EGU) -*** CAIR allowed non-EGU industrials to participate in CAIR to meet prior NO_x SIP Call requirements. EPA eliminated this option in TR, and while EPA recognizes the problem this change has created for the orphaned industrial units, no solution has been identified.
- ***Applicability date -*** CAIR, like ARP, was based on a November 15, 1990 applicability date. TR changes that date to January 1, 2005.
- ***Cogeneration/waste combustion exemptions -*** these are essentially identical to CAIR, including the biomass exclusion that modified the original CAIR rule.
- ***FIPs -*** in TR, EPA allocated credits to specific units via a Federal Implementation Plan for 2012-2013. States may apply for limited re-apportioning of allowances in 2013 and may apply for full authority to implement via state implementation plan (SIP) in 2014.
- ***Basis for allocations and fuel type -*** unlike CAIR, under TR EPA determines each existing unit's share of state allowances based on heat input with no differentiation for fuel type. The approach under TR favors units with emissions lower than the average MMBtu/hr and disfavors other units. (For new sources using the set-asides, allocations are based on emissions, not heat input).
- ***Definition of "fossil fuel" for applicability -*** under TR, EPA has clearly defined "fossil fuel" as any item of fossil origin and not just those intended as fuel. For example, plastics, tires, creosote-coated crossties, and many other fuels would be "fossil fuel" for applicability (for the solid waste combustion exemption, the traditional definition of fossil fuel still applies when calculating the 80% threshold).

Assurance Provisions: 1 ton = 1 allowance, or 1 ton = 3 allowances?

One of the biggest changes from CAIR is the *limited* interstate trading allowed. To ensure that only limited trading is allowed, EPA developed assurance provisions. For a given allocation period, if emissions in a state exceed the allocation by more than 18% (annual) or 21% (ozone season), some sources in that state will be required to submit additional allowances as a penalty. Consider this example.

State Allocation - 1,000 tons
Assurance (Penalty) Threshold - 1, 180 tons (annual)
Actual Emissions - 1,250 tons
Penalty Emissions - 70 tons
Penalty Allowance to be Submitted = 140 tons (2 times excess)

To determine which sources in that state must provide the penalty allowances, actual emissions are compared to the assurance threshold levels at the Designated Representative (DR). For each DR grouping that has actual emissions above the penalty emissions, extra penalty allowances must be submitted at a 2 for 1 ratio.

Thus, any source (rolled up to the DR level) which emits more than 1.18 (or 1.21) times the allocation level could be at risk for having to pay triple for each ton of emissions above the assurance threshold. EPA believes that the chance of reaching the assurance threshold is small, but based on the allocations in the final core rule (which are proposed for revision), some states with large differences in actual and allocated emissions are at real risk of this ocurring.

Litigation

Litigation over the TR rule is widespread—64 groups have filed challenging the rule and 8 have filed in support. In addition to electric utilities, coal providers, their trade groups, industrial associations, and the United Mine Workers union, 13 of the 27 states covered have challenged the rule: Alabama, Florida, Georgia, Indiana, Kansas, Louisiana, Michigan, Mississippi, Nebraska, Oklahoma, South Carolina, Texas, and Virginia. Those supporting EPA include traditional environmental advocacy groups (EDF, NRDC, Sierra Club, ALA) as well as three utilities with low emitting fleets: Exelon, Calpine, and PSEG Fossil.

All court filings have been consolidated into a single case, *EME Homer City Generation, L.P. v. EPA*, # 11-1302.

Key Dates

The recently signed proposed rule invites additional scrutiny of emissions budgets for technical corrections, and will have a comment submittal deadline of potentially as short as 30 days after Federal Register publication. Other key upcoming dates follow:

January 1, 2012 - TR begins for annual SO_2 and NO_x
May 1, 2012 - TR begins for ozone season NO_x
December 1, 2012 - allowance transfer deadline for ozone season NO_x
March 1, 2013 - allowance transfer deadline for annual SO_2 and NO_x
August 1, 2013 - EPA publishes states/units triggering assurance penalty provisions (proposed to be postponed until August 1, 2015)

Next Steps

EGUs subject to TR should carefully review the unit-specific allocation details promptly to provide further comments to EPA during the pending public comment period. Further, EGUs should begin assessing the potential for their state to reach the assurance threshold and base any planned usage of allocations on the potential of reaching that level. Orphan industrials must stay in touch with federal and state regulators to identify how to meet ongoing NO_x SIP Call obligations that are current unresolved. ✥

Dispersion Modeling—New Downwash Calculations Change the Playing Field

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For many people, the terms "stack height" and "dispersion model" do not ring a bell. Others grapple with these terms as they can be challenging factors in the process of obtaining an air construction permit. Have you ever constructed a stack at a specific height due to EPA guidelines and regulations surrounding Good Engineering Practice (GEP) as it relates to air dispersion modeling? Or, have you ever been told that the height of a stack at your facility is a source of high model-predicted concentrations that may be resolved by increasing the stack height? If so, be aware that any stacks historically constructed at specific heights for the purpose of showing model-predicted compliance with air quality standards, a common practice tied to the process of obtaining a construction permit, may present a problem in future modeling analysis.

In April 2011, EPA updated the approved regulatory version of AERMOD.[1] Some of the changes were expected, including coding changes to allow for the determination of 1-hour design concentrations for pollutants with new 1-hour NAAQS. Further, most of the changes did not impact concentrations predicted by the model. One change that was not expected, but that has the potential to increase concentrations, was a change to the way dispersion is simulated for stack plumes that are influenced by building downwash. The change has not been widely publicized, which is puzzling considering the potential implications resulting from an increase in model-predicted concentrations for some facilities.

Building Downwash and GEP Stack Height

The term *building downwash* describes the effect that wind flowing over or around buildings has on plumes released from nearby stacks. Essentially, buildings create a cavity of recirculating winds in the area near the buildings, and these building cavities cause increased vertical dispersion of plumes emitted from stacks on or near the buildings. Building downwash often leads to elevated concentrations downwind of affected stacks.

Cavity regions near buildings are characterized based on building geometry and wind direction. Stacks may be revised to a height such that plumes released from the stacks are outside the cavity region and thus not influenced by building downwash. The stack height at which a plume released from a stack is not excessively affected by downwash is referred to as the *GEP stack height*. The GEP stack height is the tallest height that may be utilized in the model. Although the actual height of the stack may be taller than GEP height, the stack height entered into the model cannot exceed GEP height.

More specifically, 40 CFR 51.100(ii), defines GEP stack height as the greater of:

(1) 65 meters, measured from the ground-level elevation at the base of the stack

(2)(i) For stacks in existence on January 12, 1979, and for which the owner or operator obtained all applicable permits or approvals required under 40 CFR Parts 51 and 52,

$$Hg = 2.5H$$

provided the owner or operator produces evidence that this equation was actually relied on in establishing an emission limitation
(ii) For all other stacks,

$$Hg = H + 1.5L$$

Where:

Hg = GEP stack height, measured from the ground-level elevation at the base of the stack,
H = height of nearby structure(s) measured from the ground-level elevation at the base of the stack,
L = lesser dimension, height or projected width, of nearby structure(s)

(3) The height demonstrated by a fluid model or a field study approved by the EPA, State or local control agency, which ensures that the emissions from a stack do not result in excessive concentrations of any air pollutant as a result of atmospheric downwash, wakes, or eddy effects created by the source itself, nearby structures or nearby terrain features

The equation in 40 CFR 51.100(ii)(2)(ii) stated above is also known as the "EPA formula height" or "Equation 1 stack height." In pre-2011 versions of AERMOD, the effects of building downwash were "turned-off" for plumes released from stacks at EPA's formula height on a wind direction-specific basis. Thus, historically, facilities received a benefit by raising their stacks to EPA formula height to avoid downwash. Absent dispersion techniques or other limitations, raising a stack height to the formula height was an acceptable means of demonstrating compliance in air dispersion modeling analyses.

April 2011 AERMOD Change

Historically, the turning off of downwash at the EPA formula height introduced a discontinuity in the dispersion profile (i.e., a stepwise decrease in concentration for stacks just above or just below the formula height). This discontinuity in the dispersion profile has long been recognized by EPA as an area for improvement. In a new version of AERMOD, released in April 2011,

[1] Version 11059 of AERMOD is dated February 29, 2011, but this version was not released to the public until April 7, 2011.

EPA implemented a change to the way that building downwash is considered for stacks at or above the EPA formula height. Specifically, AERMOD no longer turns off downwash above the EPA formula height. Rather, the AERMOD code allows the Plume Rise Model Enhancement (PRIME) algorithms within the model to determine when and how to apply downwash.

Impact of Change

The impacts of the change to the criteria for applying downwash are illustrated with a few simple examples. Consider a facility with a single existing stack at a height just above the EPA formula height. The maximum 1-hour model-predicted concentrations based on both the previous version of AERMOD and the April 2011 version of AERMOD are summarized in the table below:

The maximum concentration predicted by the April 2011 version of AERMOD is much higher than the maximum concentration predicted by the previous version. The reason for the increase in the maximum predicted concentration is that building downwash is not applied to the stack plume in the pre-April 2011 version of AERMOD (since the stack is taller than the EPA formula height and the pre-April 2011 version of AERMOD turns off downwash above the EPA formula height), but downwash is applied in the new version.

Max Impact Based on Previous AERMOD (μg/m3)	Max Impact Based on April 2011 AERMOD (μg/m3)
96	862

Next, consider a facility with a single building and single stack, where the actual stack height is 43 meters and the EPA formula height is 61 meters. Since the existing stack is below the EPA formula height, the plume released from the stack is affected by building downwash. The owner/operator has been contemplating an expansion for a number of years and recently decided to move forward with the expansion. The environmental manager recognized that the expansion would require an air construction permit and that dispersion modeling would be required as part of obtaining the air permit.

In late 2010, the facility was modeled using AERMOD. At that time, the maximum model-predicted concentration for a criteria pollutant based on the existing stack height of 43 meters was higher than an applicable air quality standard. Thus, the modeler considered raising the stack to reduce the maximum model-predicted concentration to less than the standard. The modeler determined that as long as the stack exceeded the EPA formula height of 62 meters, the maximum model-predicted concentration dropped significantly and was less than the standard.

However, recently the facility was modeled again, this time using the updated version of AERMOD. The goal of the modeling was to determine if the stack height determined in late 2010 would still result in modeled concentrations below the standard. Using the updated version of AERMOD, the 62 meter height previously identified as being the height above which the maximum model-predicted concentration dropped below the air quality standard, no longer resulted in concentrations less than the standard. The difference between the two AERMOD versions is the result of downwash. In the previous version, at the EPA formula height of 62 meters, downwash was turned off. In the new version, downwash is still on at 62 meters.

The modeling results described above are summarized in the table below.

The maximum concentration predicted by the model for the 60 meter tall stack is the same for both versions of AERMOD.

Modeled Stack Height (m)	Max Impact Based on Previous AERMOD (μg/m³)	Max Impact Based on April 2011 (μg/m³)
60	178	178
62	88	160

However, for the 62 meter tall stack, the older version of AERMOD predicts a much lower concentration that the April 2011 version. The example illustrates the benefit that existed when relying on the pre-2011 version of AERMOD by raising the example stack 2 meters, such that the stack is taller than the EPA formula height. The example also highlights the increase in modeled concentrations that can occur when transitioning to the April 2011 version of AERMOD. Had the facility raised its stack to 62 meters in late 2010 to yield compliant model results, future modeling for the facility could yield unacceptable concentrations simply based on the change in model version.

The complexity of the downwash algorithms and the direction-dependent nature of downwash effects (due to differing building-stack orientations for different wind directions) are such that the magnitude of the differences between the pre- and post-April 2011 versions of AERMOD vary by scenario. One thing that is clear is the change to the treatment of downwash with respect to stack heights in the currently approved version of AERMOD has the potential to cause large increases in model-predicted concentrations.

Regulations vs. Model Change

EPA has positioned the revision to the downwash criteria as a necessary change to eliminate the discontinuity in the dispersion profile for plumes released from stacks that are taller than the EPA formula height. While logic may support the removal of the discontinuity, the process by which EPA made the change is inconsistent with the existing regulations for GEP. The inconsistency is in the regulations that govern the application of dispersion models (Appendix W of 40 CFR Part 51). Appendix W indicates that cavity or wake effects should be determined for

(Continued on page 15)

GHG Quantification Reporting and Lifecycle Assessment: Does One Size Fit All?

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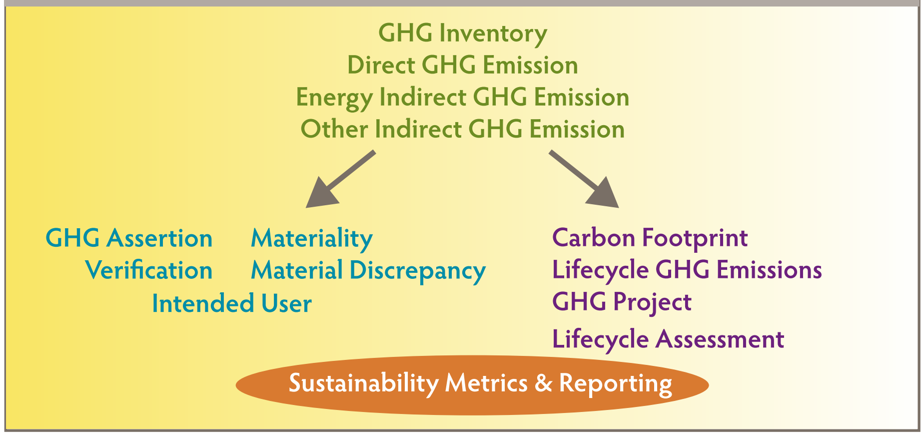
Corporate and government entities have been developing and reporting greenhouse gas (GHG) emission inventories, some for well over a decade. The basis for developing these inventories has evolved from voluntary mechanisms (e.g., sustainability reports; registries like the DOE 1605(b) or The Climate Registry) to regulatory requirements (e.g., EU Emissions Trading Scheme, US EPA Mandatory Reporting Rule, California AB 32, Canadian Federal and provincial requirements). Additionally, stakeholders continue to influence carbon disclosure through means such as shareholder resolutions and initiatives that target specific companies, industries, or segments of society.

To accommodate these trends, protocols, standards, and guidelines have progressively developed, moving from basic calculation/reporting of corporate or facility inventories to assessing the GHG impact or footprint of a company's products or entire supply chain. However, developing a corporate/facility inventory versus estimating a product/process carbon footprint requires different tools, assumptions and considerations. This article briefly examines and compares some of these protocols and standards, and presents several case examples that illustrate the differences and challenges.

GHG Definitions and Objectives

It is important to understand the underpinnings and differences between GHG inventories, carbon footprints, and lifecycle GHG emissions. In fact, some basic terms derived from the ISO 14064-1, -2 and -3 standards and PAS 2050: 2008 protocol developed by the British Standards Institute are shown in Figure 1. The terms are organized into three groups:

Figure 1. GHG Terms and Objectives



1) Those components specific to a GHG inventory (shown in green) include direct (i.e., Scope 1), energy indirect (i.e., Scope 2) and other indirect (i.e., Scope 3) GHG emissions. Scope 1 and 2 emissions are most frequently reported, while Scope 3 emissions have to date mostly been developed on a voluntary basis. One exception to this is U.S. Federal reporting of GHG emissions under Executive Order (EO) 13514 (Federal Leadership in Environmental, Energy, and Economic Performance), where annual reporting of selected categories of Scope 3 emissions is required.

2) Those components specific to the use of GHG inventory information (shown in blue), focus on the manner in which GHG emissions information is presented, assured and viewed by the user. The concept of materiality, 'that individual or an aggregate of errors, omissions and misrepresentations could affect the GHG assertion and could influence the intended users' decisions', is central to the validity of reported information. It should also be noted that GHG reporting does not always require independent verification.

3) Those that go beyond basic Scope 1, 2 and 3 GHG inventories (highlighted in purple) extend the application of GHG accounting to quantifying the carbon attributes of activities, products and processes, and carbon accounting throughout the value chain of an enterprise (i.e., from 'cradle to grave'). Such accounting also can form the basis for product certifications such as UL's Sustainable Product Certification and the Green-e GHG Reduction Product Certification.

Protocols Comparison

There are numerous protocols, standards and guidelines that can be used to develop and report carbon inventories and footprints. A selection of these is listed below:

- The GHG Protocol – A Corporate Accounting and Reporting Standard, World Resources Institute (WRI)/World Business Council for Sustainable Development (WBCSD) (2004) and Sector-specific protocols
- Specification with Guidance at the Organization Level for Quantification and Reporting of Greenhouse Gas Emissions and Removals, ISO 14064-1:2006
- Specification with Guidance at the Project Level for Quantification, Monitoring and Reporting of Greenhouse Gas Emission Reductions or Removal Enhancements, ISO 14064-2:2006
- The Climate Registry (TCR), General Reporting Protocol (GRP) (2008) and Sector-specific protocols
- Federal Greenhouse Gas Accounting and Reporting Guidance & Technical Support Document, Council on Environmental Quality (2010)

- The GHG Protocol for the U.S. Public Sector, WRI (2010)
- 10 CFR Part 300, Guidelines for Voluntary Greenhouse Gas Reporting (Section 1605(b) of the Energy Policy Act of 1992)
- 40 CFR 98, Mandatory Reporting of Greenhouse Gases (MRR)
- Specification for the Assessment of the Lifecycle Greenhouse Gas Emissions of Goods and Services, PAS 2050:2008, 2011
- Corporate Value Chain (Scope 3) and Product Life Cycle Accounting and Reporting Standards, WRI/WBCSD (2011)

Carbon offset registries (e.g., Chicago Climate Exchange, Climate Action Registry, Verified Carbon Standard and others) have established protocols for accounting, reporting and verification, as well. And, certain industries have developed tools to standardize GHG emissions reporting within their sector (e.g., American Petroleum Institute SANGEA™ Emission Estimating System).

The above listed items have similarities and differences, with selected attributes discussed as follows:

Greenhouse Gases **–** All protocols address the typical GHGs, including CO_2, CH_4, N_2O, SF_6, HFCs and PFCs. Selected protocols may go beyond these basic gases, for instance PAS 2050 includes Montreal Protocol Compounds and additional compounds can be reported optionally under TCR.

Process vs. Inventory Calculation **–** A number of the protocols address both inventory development process and calculation. In contrast, the ISO standards focus specifically on inventory process. The Federal GHG Accounting and Reporting Guidance is accompanied by a Technical Support Document that addresses detailed Scope 1, 2, and 3 GHG inventory calculation methods. Additionally the WRI/WBCSD and TCR protocols provide over a dozen sector-specific protocols/toolkits.

Consolidation Approach **–** There are two basic approaches to how entities consolidate their emissions, equity share, or operational control. Certain protocols/registries simply require that the approach be defined, although reporting on both bases often is encouraged. In contrast, Federal agencies conforming to EO 13514 must report GHG emissions associated with all activities that fall within their organizational boundaries.

Data Quality **–** This is addressed to varying degrees in all standards, protocols and guidelines (e.g., quality management systems, document retention/recordkeeping, inventory management plans). Data quality tiers are specifically designated in the TCR GRP.

De minimis**–** *De minimis* sources are treated differently among protocols. While certain protocols provide guidance and limitations for addressing such sources (e.g., WRI/WBCSD, TCR), others do not address *de minimis* emission sources. The MRR specifies industries and sources for which reporting is required, and the Federal guidance requires reporting of all GHG emissions.

Verification **–** Most, but not all, of these documents discuss verification requirements only in general terms. The ISO 14064-3 standard specifically addresses validation and verification of GHG assertions. To accompany the GRP, verification of GHG inventories submitted through TCR is governed by a detailed General Verification Protocol.

Case Examples

It would seem that there is sufficient guidance in the existing protocols to address most any GHG emission or carbon footprint calculation scenario. However, this is not always the case. Because there are underlying assumptions that will affect these calculations, there can be differences between protocols, and certain emission scenarios may not have methods that have been vetted and approved in the international community. Several examples are provided below.

Consolidation Method

Consider a scenario where a consumer chooses to make a purchasing decision based on a comparison between two companies' carbon footprints, defined as their combined Scope 1 and Scope 2 GHG emissions. This example compares GHG emissions for BP and Royal Dutch- Shell based on publicly reported data from their respective 2010 Securities and Exchange Commission 20-F filings and sustainability reports. A summary of the comparative GHG emissions data is provided in Table 1:

Table 1: Comparison of BP and Royal-Dutch Shell Scope 1+2 GHG Emissions

GHG Emission Parameter	BP	Royal Dutch- Shell
Metric Tons CO_2-e	75 million	85 million
Metric Tons CO_2-e/$mil gross revenue	252	231
Metric tons CO_2-e/employee	941	876

On an absolute basis, BP's GHG emissions are lower. When presented on an intensity basis, Royal Dutch- Shell's GHG emissions are lower. However, there is not sufficient clarity regarding the basis on which these emission estimates were developed to use this data for decision-making. Specifically, each company reports its GHG emissions on a different consolidation basis; BP on equity share, Royal Dutch- Shell on operational control. Thus, to properly make this comparison, representation on a common basis and further analysis would be required.

Reporting of Sulfur Hexafluoride Emissions

Sulfur hexafluoride (SF_6) is used in electrical transmission and distribution equipment as an insulating medium. Two methodologies that can be used to calculate fugitive SF_6 emissions are the simplified methodology outlined in TCR EPS FG-03 (based on Energy Information Administration methodology) and a mass balance approach (i.e., by tracking inventory of SF_6 over the reporting year) from EPA's Mandatory Reporting Rule, 40 CFR 98 Subpart DD.

The TCR methodology calculation is based on the distance of transmission lines multiplied by an emission factor:

(1) SF_6 Emissions (kg SF_6) = 0.558 x Transmission Miles

The mass balance approach (by tracking inventory of SF_6 over the year) is as follows:

(2) User Emissions = (Decrease in SF_6 Inventory) + (Acquisitions of SF_6) – (Disbursements of SF_6) – (Net Increase in Total Nameplate Capacity of Equipment Operated)

In one example, using equation (1), SF_6 emissions are 3.5 metric tons (about 84,000 metric tons CO_2-e), while using equation (2), SF_6 emissions are 200 pounds (about 2,200 metric tons CO_2-e). While the mass balance approach is the more accurate method, it requires appreciably more data to utilize. This example illustrates that the simplified TCR approach is overly conservative. Establishing procedures to collect the requisite data to perform a mass balance may be well worthwhile given the resulting magnitude of CO_2-e emissions.

Transmission & Distribution Losses

Transmission and distribution (T&D) losses associated with electricity use are typically considered part of a consumer's Scope 3 GHG emissions. However, an electric power generator or an entity that only transmits and markets electricity (e.g., Independent System Operator, Power Management Administration) would report these as Scope 2 emissions. Furthermore, consider a scenario where these entities only own and operate transmission lines and do not own or operate local power distribution systems.

If T&D loss related emissions are under consideration, only the scope of these emissions will differ. However, the TCR Electric Power Sector Protocol cites loss factors in the range of 0.5 to 3.5% for bulk transmission only. As illustrated in Table 2, GHG emissions from bulk transmission losses can be about 9 to 55% of that for T&D losses. The Federal GHG Accounting and Reporting Guidance does not specifically address this scenario for GHG reporting under EO 13514. This calculation can become more complex, as the TCR protocol provides guidance for instances where the transmission system owner has data for the specific sources of electricity (e.g., fossil or renewable) being carried by the transmission system.

Lifecycle GHG Emissions

There can be uncertainties and challenges when one attempts to extend GHG emissions inventories to a product or process lifecycle. Consider a scenario whereby conformance with the Federal Renewable Fuels Standard (RFS2, per the Energy Independence and Security Act of 2007) is required to generate additional quantities of renewable fuels. A project proponent petitions EPA to approve its corn-to-ethanol operation and the associated credits. The facility will be located in the U.S., with the emission reduction comparison being made with gasoline from crude petroleum. How would a project proponent perform a lifecycle assessment (LCA) of GHG emissions and estimate the requisite 20% reduction level as required by the standard?

Table 3 summarizes the results from such an analysis using two different LCA models. While the reductions compared to gasoline from crude petroleum both exceed 20%, the models provide materially different results. And there are several qualifications provided in this particular study that can influence the outcome as follows:

- ***Completeness of the LCA model data bases and underlying assumptions –*** Databases supporting LCA models are regularly updated, and may contain data that is not directly suitable for use in all applications (e.g., data predominantly from the EU for a US-based scenario).
- ***Model variability –*** Models may have varying input data flexibility, sensitivity analysis capabilities, or limited fuel production pathways, affecting the ability or ease by which project specifics can be accommodated.
- ***Farming practices and land use changes –*** These will influence the results, especially if they are not incorporated into the model. Feedstock production accounts for over 25% of the lifecycle GHG emissions in Table 3.
- ***Co-product displacement of animal rations –*** Assumptions embedded in the models must be confirmed relative to the actual production scenario.
- ***Assumptions –*** Power generation fuel mix, process energy requirements, and others can vary considerably. Consider that power generation fuel mix can be

Table 2: Comparison of T&D Loss GHG Emissions

Scenario	Scope	MWhr	Loss Factor, %	Metric Ton CO_2-e
Consumer	3	1,000,000	6.18	39,600
Electric Power Entity (T&D)	2	1,000,000	6.18	39,600
Electric Power Entity (T)	2	1,000,000	0.5 - 3.5	3,000 - 21,800

Source data adapted from Federal GHG Accounting and Reporting Guidance – Technical Support Document (2010) and The Climate Registry – Electric Power Sector Protocol (2009); for the ERCT eGRID region.

Table 3 – Comparison of Lifecycle GHG Emissions for Corn-to-Ethanol Production

Lifecycle Stage	Model 1 (gCO2-e/GJ)	Model 2 (gCO2-e/GJ)
Ethanol – Feedstock Production	23,873	24,446
Ethanol – Fuel Production	48,348	55,296
Ethanol – Co-production Credit	-17,337	-15,884
Ethanol – Combustion	2,070	650
Ethanol – Total	**56,990**	**64,508**
Gasoline – Total	**86,745**	**85,763**
Reduction	**34%**	**25%**

Source: Corn ethanol production from dry mill plant; data from ChemInfo Services Inc. (2008).

quite different depending on the region in which the proposed facility is located (e.g., whether generated predominantly by fossil fuels, nuclear, or hydro power).

Furthermore, the models used by the project proponent to develop a petition may not be the same as those utilized by EPA to evaluate it. EPA uses several models, including the Forest and Agricultural Sector Optimization Model (FASOM) and the Food and Agricultural Policy Research Institute (FAPRI) modeling system, among others. Thus, such analyses needs to carefully assess underlying assumptions and sensitivity of the model.

Conclusions

Accounting and reporting of GHG emissions is evolving from a voluntary to a statutory basis globally, with the U.S. and Canada most recently establishing requirements on the Federal and state/provincial levels. However, corporate and government sustainability considerations are driving interest in development and use of GHG emissions that extend beyond quantification of Scope 1 and 2 emissions. Quantification of Scope 3 GHG emissions and evaluation of supply chain and product lifecycle GHG emissions is becoming more commonplace, as evidenced by re-issuance of the PAS 2050 standard, issuance of the WRI/WBCSD Corporate Value Chain and Product Lifecycle Accounting and Reporting Standards, and ongoing development of a carbon footprint of products ISO standard.

Development of a GHG inventory is not necessarily a carbon footprint, per se, as they have different objectives and uses. When evaluating or verifying the results of such work, understanding the differences and assumptions is critical to setting and achieving assurance objectives.

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Dispersion Modeling—New Downwash Calculations *(Continued from page 11)*

stacks ***below*** the EPA formula height and is silent in regards to stacks above the EPA formula weight and height. The April 2011 version of AERMOD considers cavity or wake effects for stacks of any height, including stacks that are taller than the EPA formula height.

Focusing more closely on the GEP definition, Appendix W suggests that GEP is the height necessary to ***insure that emissions from the stack do not result in excessive concentrations as a result of downwash.*** *Excessive concentrations* is defined in 40 CFR 51.100(kk) which states:

(1) For sources seeking credit for stack height exceeding that established under §51.100(ii)(2), a maximum ground-level concentration due to emissions from a stack due in whole or part to downwash, wakes, and eddy effects produced by nearby structures or nearby terrain features which individually is at least 40 percent in excess of the maximum concentration experienced in the absence of such downwash, wakes, or eddy effects and which contributes to a total concentration due to emissions from all sources that is greater than an ambient air quality standard.

Simply stated, excessive concentration is a 40% increase in concentration from the concentration that would exist without downwash. The examples provided demonstrate that concentrations predicted using the April 2011 version of AERMOD are more than 40% higher than concentrations predicted using the previous version of AERMOD due to the change in the criteria for applying downwash. Since it has been established that stacks taller than the EPA formula height are needed to avoid excessive concentrations caused by downwash, stacks taller than the formula height should likely be considered GEP , even if they exceed GSM, for heights taller than the formula height.

Overall, the change to the downwash criteria in the April 2011 version of AERMOD goes beyond the intended application of downwash in Appendix W of 40 CFR Part 51. However, despite the inconsistency, it appears that EPA is moving forward with the new AERMOD version. EPA has indicated it intends to publish a guidance memorandum related to the downwash change.

Conclusion

By changing the downwash criteria used in AERMOD, EPA dramatically changed the playing field for some facilities with respect to the use of AERMOD to determine compliance with air quality standards, as the change can significantly impact model-predicted concentrations for individual facilities. This can cause concern from an air permitting standpoint and for other aspects of air quality analyses, not the least of which is the AERMOD dispersion modeling that states must conduct to assess regional compliance with the 1-hour NAAQS for SO_2.

Facilities most likely to be affected by the change include facilities with stacks above the EPA formula height, where plumes emitted from the stack were previously not subject to the influence of building downwash but, as of April 2011, are subject to downwash. There is a growing list of facilities that obtained air permits based on stack heights that resulted in modeled compliance with air quality standards prior to the change in downwash criteria that now have model-predicted concentrations in excess of the standards based solely on the model version. For the benefit of those affected by the change, the much anticipated clarification memo from EPA related to the issue may shed some light on this complex situation. ⯑

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