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February 17, 2012

EPA Administrator Lisa Jackson

EPA Assistant Administrator for Air Gina McCarthy

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Re: RFC 12003 – Concerning EPA's Methane Emissions Estimates for Unconventional Natural Gas Well Completions

Dear Administrator Jackson:

We are writing regarding a "request for correction" under the Information Quality Act (IQA), filed with EPA this past December by the U.S. Chamber of Commerce, a private industry lobbying organization. The Chamber requests that EPA abandon its estimate of emissions resulting from the completion of unconventional natural gas wells, claiming, on the basis of two industry reports, that EPA's figures are inaccurate, and that EPA's figures are improperly influencing ongoing rulemakings and academic debates. *See* Chamber Request for Correction, RFC 12003 ("RFC") at2-3.

In fact, EPA's emissions figures are well supported by a wide range of independent analyses and manifestly meet the quality, objectivity, utility, and integrity standards of the IQA. Moreover, the rulemakings the Chamber attacks – EPA's long-delayed efforts to finally promulgate comprehensive emissions standards for the oil and gas sector – would be unaffected even if the EPA emissions estimates which the Chamber alleges are too high were to be substantially lowered. Likewise, the academic and policy discussion touching on EPA's emissions estimates is active and critical, betraying no undue influence from the agency's work.

The Chamber's request is, in short, utterly without merit. Therefore, although we strongly support the agency's continuing efforts to better characterize the oil and gas industry's emissions, and encourage further research in this general area, EPA must deny the Chamber's request.

I. Background

A. EPA's Limited Obligations Under the Information Quality Act – and the Chamber's Critique

The IQA requires only that the Office of Management and Budget (OMB) "issue guidelines" that "provide policy and procedural guidance to Federal agencies for ensuring and maximizing the quality, objectivity, utility, and integrity of information" those agencies disseminate. 44 U.S.C. § 3516 Stat. Note (codifying Pub. L. 106-554). OMB's guidelines, in turn, define data quality terms and direct Federal agencies to establish "flexible" mechanisms to correct erroneous data "where appropriate." *See* 67 Fed. Reg. 8,452, 8,459-60 (Feb. 22, 2002).

EPA's own guidelines are the relevant guideposts for the Chamber's request. *See* EPA, *Guidelines for Ensuring and Maximizing the Quality, Objectivity, Utility, and Integrity of Information Disseminated by the Environmental Protection Agency* ("EPA Guidelines") (2002). The only standard in those guidelines at issue here is the agency's commitment to standards of objectivity – that is, to presenting "accurate, reliable, and unbiased" information. *Id.* at 15-16. EPA invites requests for correction, and states that it will address them thoughtfully, based in part on whether "corrective action is appropriate" at all, and upon the "significance of the error." *Id.* at 31-32.

The Chamber belatedly requests that EPA correct a figure in its "technical support document" (TSD) for Subpart W of the agency's greenhouse gas reporting program, which the agency issued in November 2010. The TSD figure updates a 1996 EPA/Gas Research Institute (EPA/GRI) study, conducted long before the boom in unconventional gas production, which, as a result, assumed that gas well completions produced almost no methane emissions. *See*, *e.g.*, TSD at 8-9 (discussing the need for these updates).

Specifically, the Chamber objects to EPA's estimate that uncontrolled unconventional gas wells emit, on average, 9,175 Mcf of natural gas per completion. RFC at 2-3. EPA arrived at this estimate by gathering independent data from several industry and government sources, as it transparently explains in the TSD.

Unconventional well completions are more complex and time-consuming than conventional well completions, and can emit a great deal more methane. Because EPA's old figures did not take this difference into account, those figures were inaccurate, and as a result EPA's inventory of methane from the US gas industry became less and less accurate as the industry transitioned to unconventional gas sources. Shale gas produced using unconventional techniques grew from under 5% of the U.S. gas supply in 1996, when the EPA/GRI study was done, to nearly a quarter of supply today, and, according to the Energy Information Administration, is on its way to constituting almost half (49%) of supply by 2035. U.S. Energy Information Administration, *Annual Energy Outlook 2012 Early Release Ove*rview (Jan. 2012) at 1-2. Moreover, since hydraulic fracturing is now being used on tight sandstone and coal bed methane wells, in addition to shale gas wells, “unconventional well completions” are even more numerous than shale gas well completions, and an even larger fraction of well completions than before.

Because it did not , and could not, anticipate these shifts in production techniques, the old EPA/GRI Study estimates that only 36.65 Mcf of methane are released into the air during each well completion, TSD at 86, an amount far below even the most conservative current industry estimate for unconventional completion emissions. Yet the Chamber nonetheless argues that EPA should abandon its efforts to account for this national shift in gas production methods as an “error.” But EPA cannot avoid taking this major change in gas production methods into account, as the Chamber requests, without violating its own IQA guidelines –the old figures clearly do not constitute accurate and reliable information on which to base updated regulations.

B. Contrary to the Chamber’s Assertions, EPA’s Estimates of Natural Gas Emissions from Uncontrolled Unconventional Gas Wells are Reasonable and Reflect Accurate, Reliable and Current Empirical Information.

EPA’s updated figure is based upon four sets of emission estimates. The first of these estimates is based on EPA’s analysis of the Energy Information Administration’s data, to determine natural gas emissions from the nearly 8,000 unconventional wells completed in 2002. EPA essentially averaged the total emissions that were attributable to unconventional wells over the unconventional wells in this population, to come up with an estimate of ~6,000 Mcf of emissions per well. TSD at 86 (citing EPA, *Green Completions*, Natural Gas STAR Producer’s Technology Transfer Workshop (Sept. 21, 2004) at 4).

EPA also drew from three sets of “green completions” data. In a green completion, most if not all wellhead emissions are captured, rather than vented or flared. As a result, reports of the volume of gas captured for sale (not released into the air) during a green completion provide a very reasonable estimate of the volume of natural gas which would have been emitted during the well completion if not captured. TSD at 86-87. The first of these data points is based on data from Devon Energy, reporting that the company recovered an average of 11,900 Mcf of natural gas per green completion across 30 unconventional wells in the Fort Worth Basin. *Id*. (citing *Green Completions* at 13). EPA also had data from Weatherford, estimating approximately 700 Mcf of natural gas per completion based on three test green completions in the Fruitland coalbed methane formations in Colorado. *Id.* (citing *Green Completions* at 14). Finally, and perhaps most significantly, EPA also drew on a 2007 report on 1,064 green completions in tight sandstones in Colorado, which captured 23,701 Mcf of gas per well (though EPA rounded down to 20,000 Mcf of gas per well). *Id.* (citing EPA, *Reducing Methane Emissions During Completion Operations* (Sept. 2007) at 14).

Averaging all of these data points, EPA concluded that approximately 9,175 Mcf of natural gas, including over 7,000 Mcf of methane, is emitted into the atmosphere in each uncontrolled unconventional gas well completion. TSD at 87.

The Chamber roots its objection to this estimate in two reports, by two industry consulting firms, IHS CERA and URS. These reports were submitted to EPA during the comment period for its ongoing oil and natural gas production sector emissions standards rulemaking and EPA is considering them in that docket.[1] The Chamber nonetheless later filed its separate request for correction, resubmitting the reports to the agency.

In its request, the Chamber argues, based on the IHS CERA report, that EPA erred by taking a simple average of the four data points, that it should not have used green completion data at all, and that EPA assumptions about the percentage of emissions vented rather than flared improperly influenced the 9,175 Mcf figure. RFC at 3-4. Then, based on the URS Report, which provides a sample of emissions from industry-selected wells to argue that average emissions are 765 Mcf/completion , the Chamber argues that actual well emissions are "1200% lower" than EPA's estimates, that green completions are more common than EPA supposes, and that flaring (as opposed to venting) is more commonly used than EPA estimates. RFC at 4. Because of these supposed errors, the Chamber argues that EPA's estimate is contrary to the IQA and the relevant IQA guidelines. *Id.* at 4-5.

We retained an independent oil and gas expert, Ms. Susan Harvey, to review the data before EPA, and the data included in the reports submitted by the Chamber. As the attached report from Harvey Consulting demonstrates in more detail, the Chamber's arguments (where they are not wholly irrelevant) lack foundation.[2] EPA's estimates are well within the range of reasonable accuracy, and are supported by additional data. Moreover, even if completion emissions were somewhat lower, important regulatory decisions based on those estimates would not be meaningfully affected. Because EPA's estimates meet the baseline standard of "objectivity, utility[,] and integrity," they are consistent with the IQA guidelines.

II. The Chamber's Request Is Irrational and Unreasonable – It is Not Supported By Its Own Reports, and Is Directly Contradicted By Independent Data

[1] *See, e.g.* EPA-HQ-OAR-2010-0505-4241 (NSPS docket comments attaching URS study); EPA-HQ-OAR-2010-0505-4233 (same, attaching both URS study and IHS CERA study).

[2] Attached as Ex 1, along with Ms. Harvey's CV. We note that Ms. Harvey's memorandum has been drafted as a response to comments filed by the American Natural Gas Alliance and the American Petroleum Institute in EPA's new source performance standards rulemaking document, and so discusses those comments. Because those comments are based, in relevant part, on the industry reports the Chamber cites, the Harvey Report is directly on point in these circumstances as well.

The Chamber's request fails for many reasons. EPA's analysis is well-supported, both on its own data and by other independent reports; the Chamber's criticisms, on the other hand, have no substantial support. Moreover, some of the "errors" it identifies simply have nothing to do with the 9,175 Mcf/completion figure and so are irrelevant.

A. The Chamber's Criticisms Are Without Merit

The Chamber argues that the URS/ANGA data show that uncontrolled well completion gas emissions are much lower than EPA estimates, and, based on the IHS CERA report, both that EPA should not have averaged its data points together, and that the data from green completions does not meaningfully address well completion estimates. RFC at 3-4. Each of these criticisms is wrong.

i. The Chamber's Alternate Emissions Figure Is Unsupported

The Chamber argues that data from the URS study shows that the "actual" emissions from unconventional well completions are just 765 Mcf of natural gas per completion. RFC at 4. This conclusion is totally unsupported, and is contradicted by the available independent data.

To begin with, the Chamber's claims are based upon an entirely unrepresentative data set, contained within the URS study. That study presents a sample of just under 1200 wells (of which 1,076 received green completions) gathered from companies which are members of America's Natural Gas Alliance (ANGA), an industry association. *See* RFC at 4; URS Report at 2-3. As the attached Harvey Consulting report makes clear, the ANGA/URS data is simply not representative of the universe of relevant wells. URS collected data from 7 ANGA oil and gas exploration and production companies (two of which performed no green completions); there are at least 95 large and 6,329 small such companies in the country, Harvey Report at 4, meaning that the URS data covers just 0.1% of all such companies. *Id.* Likewise, more than 27,000 new gas wells are drilled annually, meaning that URS's sample represents just 4.3% of all wells drilled each year. *Id.*

The Chamber bases its emissions estimate upon an unrepresentative subsample of this already cherry-picked collection of wells. It points to a collection of just 98 wells which did not have green completions within the URS dataset. *See* URS Report at Table 6. Thus, the Chamber's claim is based on a grand total of 0.36% of the 27,000 wells drilled each year. Worse, the wells without green completions in the URS sample are *not* representative because they are the very wells on which operators have explicitly decided *not* to perform a green completion. Such wells "are commonly low flow rate and low-pressure wells." Harvey Report at 6. Thus, as the Harvey Report explains, "by definition," such wells "would not be representative of the higher gas flow rate and higher gas pressure" wells on which green completions would ordinarily be performed, or could be performed. *Id.* The conclusions drawn from URS survey of a few non-representative wells, in short, are essentially meaningless.

In contrast, available independent evidence shows that well completion emissions are very likely to be at or near the level EPA's estimates, if not above them. First, 2001 data from the Energy Information Administration recorded that the average initial gas flow rate from all U.S. wells completed between 1996 and 2000 was 1,900 Mcf/day during the completion; assuming just 5.8 days per completion, as ANGA and URS do, this translates to 11,020 Mcf/completion – a somewhat *higher* figure than EPA's. *See* Harvey Report at 9 (citing EIA data). Moreover, many green completions take longer than 5.8 days (EPA assumes up to 10 days, based on industry data, O&G TSD at 4-16), so using a 5.8 day period to calculate emissions is conservative.

Likewise, 2008 data from ALL Consulting reported a range of flow rates during completion for shale gas plays varying from 415 to 3,100 Mcf/day across most shale plays. Harvey Report at 10 (citing ALL Consulting data). Using the conservative 5.8 day completion estimate from URS/ANGA, these emissions rates translate into between 2,407 Mcf/completion to 17,980 Mcf/completion, bracketing EPA's 9,175 Mcf/completion figure, and well above URS's 765 Mcf/completion figure. *Id.* Indeed, recent data from a Simmons & Co. report indicate a range of 4,000 – 7,000 Mcf/day even for *conventional* well completions, and 1,200 – 3,000 Mcf/day for completions in unconventional sand wells; the combined range from 1,200-7,000 Mcf/day translates into between 6,900 Mcf and 40,600 Mcf of methane emissions per completion. Harvey Report at 10 (citing Simmons Consulting data). These figures, too, suggest that EPA's estimate is not only reasonable but may be a low estimate of uncontrolled well emissions.

Moreover, a survey of 2009 EIA data on gas production for *all* wells – including low-pressure wells, aging wells, conventional wells and so on – and covering all periods, not just completions, gives a national production rate of 148.5 Mcf/day, which would translate into 861 Mcf per completion using the 5.8 day figure *See* Harvey Report at 7. But, of course, EPA's 9,175 Mcf/completion number is for *completions* on unconventional wells – unlike the national average rate, it reflects the earliest production from unconventional wells which will produce more than an average well, averaged over its lifetime. Thus, the emissions from *those* well *completions*, as the 2001 EIA data, the ALL Consulting and Simmons & Co figures demonstrate, are far higher. The fact that URS's 765 Mcf/completion figure is, instead, close to the national average production rate for *all* wells, including those measured long after completion or which produce very little, shows how unreasonably low that estimate is.

Finally, very recent empirical atmospheric measurements demonstrate that, if anything, natural gas production systems emit more, not less, than EPA estimates. Researchers affiliated with the National Oceanic and Atmospheric Administration and the University of Colorado have recently released a peer-reviewed study documenting very high levels of alkanes (including methane) near an unconventional gas field in the Denver-Julesberg Basin of Colorado. *See* Gabrielle Pétron *et al*., *Hydrocarbon Emissions in the Colorado Front Range – A Pilot Study*, Journal of Geophysical Research, *in press* (2012).[3] The researchers compared their results to emissions calculated from EPA's inventory estimates for oil and gas production sources, concluding that "[t]he methane source in Colorado is most likely underestimated by at least a factor of two." *Id.* at 43. Although the paper does not differentiate between methane coming from completions and other sources in the production sector, it recognizes that completion venting emissions are contributing to the high methane levels. *Id.* at 32. Thus, the Pétron *et al.* study, at a minimum, demonstrates that gas production operations as a whole (and completions in particular) are large methane sources and, collectively, are larger than EPA supposes. It thus further shows that the Chamber's argument that EPA's figures are too *high* is wholly unsupported by the evidence.

In short, all available national data supports well completion emission rates in the thousands of Mcf per well (if not the tens of thousands of Mcf for some wells). No data confirms the extremely low completion figures calculated by URS on the basis of its tiny sample of unrepresentative low-flow wells.

ii. The Chamber's Procedural Arguments Also Miss the Mark

With its own figure hopelessly off-base, the Chamber is reduced to arguing that EPA has made procedural errors in two regards. Neither charge sticks.

First, the Chamber suggests that EPA should not have averaged together its four emissions figures, pointing out, on the basis of the IHS CERA report, that each of the four figures is based on different numbers of wells. RFC at 3. But even if the Chamber is right that EPA should have combined the data points differently (and it offers no alternative methodology), this point does not support its argument that EPA's figures are far too high. The table below shows EPA's four data points, and the number of wells supporting each:

Emissions (Mcf/completion)	700	11,900	23,701	~6,000
Number of Wells Supporting Estimate	3	30	1,064	7782

Presumably, the Chamber would prefer that EPA weight estimates supported by larger samples more strongly. As the chart suggests, the figures supported by large numbers of wells are 23,701 and approximately 6,000 Mcf/completion; these figures, though disparate, bracket EPA's average 9,175 Mcf figure, and are consistent with the estimates discussed above, which are all in the thousands of Mcf per completion. Indeed, simply

[3] Attached as Ex 2.

weighting each average by the number of well completions it represents gives an average of 8,138 Mcf / completion, over ten times greater than the URS/ANGA figure. Only EPA's least-well-supported figure – the 700 Mcf figure that EPA based on three experimental wells[4] - jibes with the URS/ANGA estimate on which the Chamber relies.

The Chamber might also argue that EPA should give more weight to data points based upon directly measured wells. But two of EPA's three directly measured data points are *higher* than EPA's 9,175 Mcf estimate – the 11,900 Mcf figure based upon 30 wells and the 23,701 Mcf figure based upon 1,064 wells. EPA would presumably still weight these samples more heavily than the 3 wells in the Fruitland experience, and so, again would likely wind up with a higher figure than it is currently using.

In short, the Chamber's "averaging" argument is simply not persuasive.

The Chamber's other procedural argument is no more compelling. It posits, based on the IHS CERA report, that EPA's numbers are high because three of its four data points are based on green completion data. However, one of EPA's data points and the one with the largest well sample size – the 6,000 Mcf figure – is not based on green completion data at all, and is still far higher than the URS/ANGA figure. Moreover, it is supported by the independent data analyses discussed above. So, again, even if EPA's data is imperfect, it is clearly not so beyond the bounds of reasonableness as to be inaccurate for IQA purposes. On the contrary, EPA has presented useful information based on the most accurate data available, and the Chamber has not provided any reason to believe EPA's figures are not accurate.

B. Several of the Chamber's Criticisms Are Not Just Wrong, But Irrelevant

The Chamber also argues that EPA's 9,175 Mcf natural gas per completion emissions estimate is somehow flawed (the Chamber does not say how) by the agency's determination that roughly 15% of wells have green completions annually, and that 51% of emissions from the remaining wells are flared rather than vented. These estimates have no bearing whatsoever on EPA's baseline emissions figure, and, in any event, are supported on the evidence before EPA.

To begin with, the figure that the Chamber is attacking is an estimate of how much methane would be emitted during an unconventional well completion *with no controls*,

[4] This 700 Mcf figure should, if anything, be further discounted because it is based on green completions in a coalbed methane play. The production profile of coalbed methane wells differs from that of shale gas or tight gas wells. In order to produce gas, coalbed methane formations must first be "dewatered." As water is produced from the formation, gas begins to flow. This means that, unlike other unconventional well types, the initial gas production rate in coalbed methane wells is low, and increases as more and more water is produced, eventually reaching some peak rate. In shale gas and tight gas, the highest gas production rate in the life of the well is the initial production rate. Consequently, the emissions per completion of coalbed methane wells are not representative of other unconventional well types.

yet it is attacking that estimate by citing EPA determinations regarding how *controlled* wells behave. This attack does not make sense. Uncontrolled completion emissions depend upon the geology of the producing formation and the process used to stimulate the well, but do not, of course, depend on how those emissions are treated once they reach the surface. To put the point simply: When calculating the emissions of an uncontrolled well behaves, the emissions of controlled wells, or which controls are used at *those* wells, are not relevant. Thus, EPA's estimates of *uncontrolled* well emissions have nothing to do with EPA's separate analyses of available emissions controls.

But even if the Chamber's critiques mattered, they would still be wrong. First, the Chamber argues that EPA is wrong to think that only ~15% of all wells receive green completions. It bases its argument, once again, on the unrepresentative URS data. 92% of the wells in that sample had green completions, URS Report at 3; the Chamber seeks to extrapolate this figure to argue that *most* wells nationally – not just in the self-selected industry sample – had green completions. This approach does not make sense. Simply put: There is absolutely no reason to suppose that a tiny, industry-selected sample of companies performing green completions says *anything* about the percentage of such completions performed nationwide.

To the contrary: industry-wide data, including an EPA analysis that was independent of the figure the Chamber challenges, and reports by the American Petroleum Institute (API), demonstrate that the URS sample is not representative. In a control technology analysis that did not depend upon EPA's completion figure, EPA estimated that about 15% (a range of 14-19%) of U.S. wells used green completions – a figure which translates into 3,000 to 4,000 green completions annually. *See* EPA, *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution* ("O&G TSD") (2011) at 123. In comments on EPA's proposed new source performance standards (NSPS) for the industry, API likewise reported that there are approximately 300 green completion equipment units in existence, which could perform up to 4,000 green completions annually – a figure identical to EPA's upper-end estimate. *See* API Comments at 94; Harvey Report at 2.

To state the obvious, then: available evidence demonstrates that 92% of the *27,000* wells drilled annually cannot possibly be receiving green completions. Under a strong revised set of oil and gas new source performance standards, the share of wells completed in this way must and will rise as operators are required to consistently employ this profitable, and important pollution control measure. Such rules will also provide a very strong incentive for the rapid manufacture of more green completion equipment.[5] But, without such standards, URS's figure cannot be taken as representative of the industry as a whole.

[5] We note that API argues, elsewhere, that it will take several years to produce sufficient equipment. We do not agree with this assessment: The industry's rapid ramp-up in the shale gas plays demonstrates that

The Chamber's second claimed error – this time over EPA's finding that approximately 51% of wells without green completions are flared and the remainder vented, *see* TSD at 88, RFC at 3-4 – is also uncompelling. This estimate simply does not bear at all on the 9,175 Mcf/completion figure for uncontrolled wells (that gas or its combustion products are emitted into the atmosphere whether vented *or* flared; when calculating methane emissions for the greenhouse gas inventory, flaring is accounted for separately of the 9,175 Mcf/completion factor). Whether or not gas is vented or flared, it is not captured and sold, meaning that the venting vs. flaring question does not speak to the agency's efforts to promote more capture, rather than either of these alternatives.

The Chamber's criticisms on these grounds, in short, are both immaterial and wrong.

C. In Sum, The Chamber's Data Quality Arguments Fail

The Chamber's arguments are, in short, either irrelevant, wrong, or both – and are universally contradicted by independent emissions data and by atmospheric measurements. In fact, they are directly contradicted even by the American Petroleum Institute, which is often highly critical of EPA. In comments on EPA's proposed emissions standards, API offered a few caveats, but largely used EPA's estimates, accepting, for the sake of argument, that they are "as reasonable an estimate as anyone is likely to develop," and basing its own calculations on EPA's figures. API Comments, Attachment G at 6. We agree with API that EPA's figures are manifestly reasonable. They are, in fact, plainly accurate, as they fall squarely in the range of accepted emissions estimates for this industry. As such, they are consistent with the IQA's objectivity and accuracy requirements, and do not warrant correction.

III. The Chamber Errs in Asserting That the Data Show that EPA's Emissions Figures Should be Altered In Ways Which Could Substantively Affect the Agency's Rulemaking Decisions or Academic and Policy Debates

Moreover, even if EPA's 9,175 Mcf/completion figure were not entirely accurate, any remaining inaccuracy is insignificant. Most importantly, that figure could fall substantially without altering EPA's conclusions regarding the form of its recently proposed new source performance standards. Thus, though EPA certainly can and should continuously improve its emissions estimates in response to new information, the Chamber cannot show that that process could cause EPA to retreat from its wellhead emissions regulations. On the contrary, the data support EPA's updated emissions estimates.

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it can rapidly produce new equipment when it chooses to do so and the NSPS will require such production to ramp-up quickly.

Further, the emissions figure has also had no improper influence on government and independent research, despite the Chamber's claims. Instead, it has been part of an ongoing healthy scientific dialogue.

A. The Form of the Proposed New Source Performance Standards Is Not Sensitive to EPA's Particular Emissions Estimates

The Chamber observes that EPA's proposed New Source Performance Standards (NSPS), which require green completions in most circumstances for unconventional well completions, are justified in part on the 9,175 Mcf/completion figure. *See* RFC at 7; *see also* O&G TSD at Table 4-8. Naturally so: companies which capture gas can resell it, offsetting the cost of controlling volatile organic compounds and other pollutants emitted during completions. But while the Chamber implies that this cost of control decision is very sensitive to EPA's precise emissions estimate, that conclusion is actually quite durable, both legally and technically, and would not change even if EPA altered its estimates substantially in response to new information.

This is because EPA is to require emissions controls consistent with the best "system of emission reduction," 42 U.S.C. § 7411(a)(1), a question it answers in part by showing that the "costs of using the technology are not exorbitant." *Lignite Energy Council*, 198 F.3d 930, 933 (D.C. Cir. 1999). This is a low hurdle: The question is not whether individual wells, or even individual companies can bear the cost, but whether the cost of new source control is "greater than the industry could bear and survive." *Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975). In the context of green completions, this means that even if wells emitted substantially less gas – and so less gas could be captured and sold to offset emissions control costs – green completions would still be required by law, provided that their costs were not truly exorbitant. In fact, EPA has shown that, under most circumstances, green completions not only do not impose unreasonable costs, but are actually *profitable* at the emissions rates it estimates.

To show as much, we have assembled a wide range of cost estimates for green completions, including those which EPA used in the NSPS rulemaking. As the table shows, this cost of control analysis responds to both emissions estimates and the cost of natural gas. More importantly, it demonstrates that both emissions and prices must fall to very low numbers before the cost of control is equal to the revenues from captured gas. Importantly, this "break-even" point is, of course, not the minimum point at which EPA could impose controls under the standard articulated above – but merely demonstrates that the industry breaks even at emissions rates well below EPA's estimates.

		$ / well	Mcf / well	Mcf / well	Mcf / well	Mcf / well
Source	**Year**	**Total expense per well**	**Volume of NG required for break-even at following prices***			**Volume of saved NG as reported**
			2.5 $/Mcf	4 $/Mcf	5.5 $/Mcf	
EPA Lessons Learned[6] (purchased equipment)	2011	8,850**	3,540	2,213	1,609	10,800
EPA Lessons Learned (rented equipment)	2011	33,000	13,200	8,250	6,000	10,800
EPA - NSPS TSD[7]	2008	33,237	13,295	8,309	6,043	8,258
EPA[8]	2005	14,000	5,600	3,500	2,545	7,000
Devon Energy[9],[10],[11]	2004, ’05,’07	8,700	3,480	2,175	1,582	11,740
BP[12],[13]	2005, ’07	12,264	4,906	3,066	2,230	7,500
Williams[14]	2006	14,444	5,777	3,611	2,626	22,515
Simple average (of above data)		17,785	7,114	4,446	3,234	11,230

* Does not account for revenue from condensates
** Based on an equipment cost of $500,000 that is spread out over 5 years, and annual costs of $121,250. The equipment is expected to serve over 5 years and 25 well completions per year. Time value of money is neglected.

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[6] U.S. EPA, Lessons Learned from Natural Gas STAR Partners, Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells, 2011

[7] U.S. EPA New Source Performance Standards, Technical Support Document (NSPS TSD), pages 4-15 – 4-18.

[8] U.S. EPA Natural Gas STAR, Cost-Effective Methane Emission Reductions for Small and Mid-Size Natural Gas Producers, Corpus Christi, Texas, November 1, 2005.

[9] U.S. EPA, ExxonMobil Production Company, and American Petroleum Institute, Green Completions, Lessons Learned from Natural Gas STAR, Producers Technology Transfer Workshop, September 21, 2004.

[10] Devon Energy, EPA Natural Gas STAR Program Presentation, March 2007.

[11] U.S. EPA and Devon Energy, Reduced Emissions Completions (Green Completions), Lessons Learned from Natural Gas STAR, Producers Technology Transfer Workshop, Casper, Wyoming, August 30, 2005.

[12] Ibid.

[13] Gordon Reid Smith, Natural Gas Industry Green House Gas Control & Business Opportunity, Presentation, 2007.

[14] The Williams Companies, "Reducing Methane Emissions During Completion Operations – Economics Volume Recovered." Williams Production RMT – Piceance Basin Operations. 2007 Natural Gas Star - Production Technology Transfer Workshop. September 11, 2007.

The table shows that EPA's projected expenses for green completions in its NSPS rulemaking are higher than many estimates provided by many oil and gas companies, and are also higher than some past EPA estimates. As a result, cost comparisons based on the NSPS figures are quite conservative. Even a comparison based on the NSPS cost figures, however, shows that producers who capture 8,309 Mcf of gas break-even with gas at $4/Mcf. Using a broader range of green completion cost estimates, the break-even point at this gas price ranges from just over 2,000 Mcf to 8,309 Mcf per completion – all hundreds to thousands of Mcf below EPA's 9,175 Mcf/completion figure. At higher gas prices, this break-even point falls still lower – down to as low as just over 1,600 Mcf per well. Thus, emissions from wells could in fact be significantly below EPA's current reasonable and best estimate without causing the agency to alter its determination that green completions impose reasonable costs on the industry.

Moreover, it is important to note that this break-even analysis is conservative because it does not account for any revenue from condensates, which would be captured along with gas. Condensates can be expected to provide about $7,000 in revenue per completion.[15] Depending on the scenario above, this revenue would either more than compensate for any natural gas shortfall for breaking even, or significantly mitigate any shortfall.

Importantly, though gas prices are presently at record lows, the EIA and independent analysts all project gas prices to be well above $4/Mcf (in 2010 dollars) within the next five years, as the attached report from Synapse Energy Economics demonstrates.[16] Although the EIA's Annual Energy Outlook for 2012 reflects the recent drop in prices, it projects wellhead prices of over $4/Mcf (in 2010 dollars) by 2017, climbing above $5 by 2025. *See* EIA, Annual Energy Outlook 2012, Table A13.[17] Thus, most gas completions will hit the break-even point over the life of the rule, even at emissions figures well below EPA's estimates.

In short, even if gas prices stay very low (which is unlikely), gas capture will offset the costs of green completions sufficiently to prevent those costs from being anywhere near "exorbitant" for the industry as a whole, and, in fact, gas capture is likely to allow the industry to break-even, or even profit, from EPA's proposed rules. Even if EPA were to lower its estimate somewhat, within the bounds of available data, these cost conclusions would not change – green completions would still impose only reasonably costs on the industry. There is, therefore, no reason to think that the precise 9,175 Mcf/completion figure EPA derived is driving EPA's analysis in the proposed rule. Although that figure is certainly reasonable and accurate, EPA would be required to

[15] U.S. EPA, Lessons Learned from Natural Gas STAR Partners, Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells, 2011
[16] Attached as Ex. 3.
[17] Attached as Ex. 4.

impose a green completion requirement even if the figure were to be lowered substantially.

B. EPA's Emissions Figures Have Not Otherwise Unduly Influenced the Debate

The Chamber, finally, offers that EPA's figures have unduly influenced several other studies by the Department of Energy (DOE), the National Energy Technology Lab (NETL), and Cornell University, and so warrant correction. Even if EPA's figures were inaccurate, the Chamber's arguments would be wrong because the cited studies do not accept EPA's figures uncritically but, instead, carefully and independently considered EPA's estimates as part of a larger analysis. The EPA figures, in other words, are being discussed in a robust academic debate, precisely as they should be – and are being treated, appropriately, as reasonable, but not dispositive. There is no reason for EPA to "correct" its work in response to the Chamber's erroneous arguments, or to prevent undue damage to the debate over these estimates; rather, the agency should simply monitor the discussion and learn from it.

For instance, the NETL report the Chamber cites, which is a life-cycle analysis of the industry's overall emissions, carefully parsed EPA's figures and explicitly accounted for any uncertainty. *See generally* Timothy J. Skone, NETL, *Life Cycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery, and Electricity Production* (2011). NETL began with EPA's figures, but "made adjustments" to distinguish between different types of gas wells, and to account for variability in industry practices over the years. *See id.* at 32-34. NETL also carefully checked its own results to ensure that they were not overly sensitive to any one emissions assumption (including estimates of completion emissions), and to understand how its conclusions would vary with different figures. *See id.* at 24-25. Thus, there is no evidence that the NETL study was improperly influenced by EPA's figures.

The Cornell paper, by Howarth *et al.*, which is also a life-cycle analysis, similarly offers no support for the Chamber's argument. *See generally* Howarth *et al.*, *Methane and the Greenhouse-Gas Footprint of Natural Gas from Shale Formations*, 106 Climatic Change 679 (2011). That study, too, begins by relying on EPA's completion emissions figures, *see id.* at 681, but does not end there. Instead, the Howarth paper draws from a range of completion emissions for different shale plays, not just EPA's numbers, *see id.* at 682. There is no evidence that EPA's particular figure dispositively influenced that paper's completion emissions estimates – even if such influence were problematic, which it is not.

Notably, the Cornell and NETL papers disagree with each other as to the ultimate magnitude of the gas industry's life-cycle emissions. *Compare* NETL Report at iv (concluding that gas life-cycle emissions when used for electricity are well below those of coal); Howarth *et al*. at 687 (concluding that gas life-cycle emissions when used for electricity are likely equivalent to, or higher, than of coal). So, if EPA's supposed "error" is somehow unduly affecting the conclusions of research papers, as the Chamber argues, *see* RFC at 6, it would have to be doing so in opposite directions at once. Of course, it is not: EPA's conclusions are relevant to the debate, but they plainly are not dispositively shaping this academic dispute, as they constitute the partial bases for papers which come to diametrically opposed conclusions.

Finally, the DOE report that the Chamber cites offers the Chamber no support. That report does not even cite EPA's figures. *See* DOE, Secretary of Energy Advisory Board, *Shale Gas Production Subcommittee 90-Day Report* (Aug. 18, 2011). The Chamber quotes DOE as referring to a "pessimistic conclusion about the greenhouse gas footprint of shale production and use," RFC at 6, but DOE was *not* referring to EPA's completion estimate. Instead, DOE was discussing the conclusions of Howarth *et al.*, *see* DOE Report at 17, without endorsing them: the Chamber's partial quotation omits the next phrase, which states that, in DOE's view, that pessimistic conclusion is "not widely accepted," *id.* DOE then called for further debate on the broad question of the industry's greenhouse gas emissions, *id.*, leaving EPA's analysis of the narrow completion emissions issue undisturbed and uncited.

In short, the Chamber offers no evidence that anybody has unduly "relied on EPA's flawed estimate," as it asserts, RFC at 6. Instead, EPA's estimate, which is not flawed, has been cited in a vigorous academic debate – a debate which it has not settled, and which will, if anything, ultimately act to further improve our knowledge of emissions associated with oil and gas production. There is no reason for EPA to withdraw its figure; rather, it should welcome the ongoing discussion to which it has contributed.

III. Conclusion

The Chamber's request is, in sum, composed entirely of irrelevant and unsupported arguments. EPA's completion emission estimate is well-supported, and within the range of emissions figures provided by numerous independent data sources. It therefore represents accurate, reliable and current information about well completion emissions, consistent with the Agency's own IQA guidelines, and EPA must deny the Chamber's request.[18]

[18] Indeed, EPA might opt not even to respond to the Chamber's request separately from its response to comments on the NSPS. EPA does not divorce its IQA processes from the agency's daily activities, consistent with OMB's direction that the IQA guidelines are to be "appl[ied] in a common-sense and workable manner" that does not "impose unnecessary burdens." *See* 67 Fed. Reg. at 8,453.Therefore, EPA "generally [will] not consider [an IQA] complaint that could have been submitted as a timely comment in the rulemaking or other action but was submitted after the comment period." EPA Guidelines at 33. EPA generally responds, if at all, to such issues in the response to comments on the affected agency action, rather than in a separate document. *Id.* Here, the URS and IHS CERA reports are already in the NSPS docket, and EPA can respond to them there, rather than in a separate, extraneous, proceeding.

Sincerely,

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Exhibit 1

HARVEY CONSULTING, LLC.

Oil & Gas, Environmental, Regulatory Compliance, and Training

Memorandum

Date: February 13, 2012

To: Meleah Geertsma, NRDC
Craig Segall, Sierra Club

Re: Review of Reduced Emission Completion Estimates Used by EPA and Critiques of EPA's Estimates Completed by IHS CERA, URS (for ANGA) and API

This memo responds to your request to review the Reduced Emission Completion (REC) estimates used by the Environmental Protection Agency (EPA) in the proposed New Source Performance Standards (NSPS) for the Oil and Gas Industry Sector (Docket ID No. EPA-HQ-OAR-2010-0505) and respond to the America's Natural Gas Alliance's (ANGA) and American Petroleum Institute's (API) critiques of EPA's estimates. This memorandum responds to three questions:

Question No. 1: EPA estimates that 15% of all U.S. wells use Reduced Emission Completions (RECs), whereas American Petroleum Institute (API) assumes 20% and America's Natural Gas Alliance (ANGA) assumes 92%. Is EPA's 15% estimate well supported?

EPA's proposed rule assumes that industry currently has a capacity to complete approximately 3,000 to 4,000 REC jobs per year in the United States.[1]

EPA assumes that 9,313 new gas wells and 12,050 existing gas wells will be drilled and hydraulically fractured in the U.S., and 8,258 Mcf/well (methane) could be captured using REC equipment.[2] As a result, EPA forecasts the need for 21,363 REC jobs per year.

Assuming there is a need for 21,363 REC jobs per year, and there is currently capacity to complete 3,000-4,000 REC jobs per year, EPA's estimates show that 14-19% of wells are currently receiving REC control.

[1] EPA, Technical Support Document for Standards of Performance for New Stationary Sources: Oil and Natural Gas Production and Natural Gas Transmission and Distribution; National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities; and National Emission Standards for Hazardous Air Pollutants From Natural Gas Transmission and Storage Facilities, Docket ID No. EPA-HQ-OAR-2010-0505, 2011, p. 123 of 604.

[2] EPA, Regulatory Impact Analysis, Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry, July 2011, p. 3-21.

3,000 REC capacity/ 21,363 REC jobs needed = 14% of wells use REC
4,000 REC capacity/ 21,363 REC jobs needed = 19% of wells use REC

API reports that there are 300 REC units in operation, with the ability to complete 4,000 REC jobs per year.[3] API's estimate agrees with EPA's upper-end estimate of 4,000 REC jobs per year.

API estimates that an additional 16,000 wells per year could be processed by REC if there were sufficient REC capacity.[4] API estimates that 20% of U.S. gas well emissions are currently being captured with REC units.

4,000 REC capacity/ 20,000 REC jobs needed = 20% of wells use REC

The only significant difference in the EPA and API estimates is the assumed REC equipment capacity. EPA assumes less capacity (3,000-4,000 REC jobs per year) than API's estimate of 4,000 REC jobs per year.

ANGA does not provide any data on the number of RECs currently in service to support its analysis.

> Based on currently available REC equipment capacity EPA estimates that only 14-19% of wells are currently controlled using RECs. API estimates 20%. ANGA does not provide data on REC equipment availability.

On November 30, 2011, ANGA submitted comments to EPA on Docket ID No. EPA-HQ-OAR-2010-0505. ANGA's comments included a November 28, 2011 analysis by URS on 1,174 wells completed by ANGA members.[5] All of the 1,174 wells were new wells, except two.

The purpose of the URS study was to determine whether EPA's assumption that only 15% of well emissions are currently captured using REC equipment is correct. The URS study concluded that 92% of U.S. well emissions are captured by RECs, and EPA has underestimated industry's REC use.

URS' analysis reportedly compiled gas well completion data on 1,174 wells that was supplied by seven upstream exploration and production (E&P) companies in the U.S. URS found that of the 1,174 wells it studied, 98 wells were completed without REC emission control. The remaining 1,076 wells used REC emission control. From this data URS concludes that 92% of the wells in its study were completed using REC techniques.

1,076 wells used REC/ 1,174 wells surveyed by URS = 92% of wells in survey used REC

ANGA's URS study does not include any data on the number of RECs currently in service to support its analysis. The study goes no further than to document that 1,076 REC jobs were completed during an 8 month period (January – August 2011) by five member companies. URS's survey data was based on seven companies, so two of the seven completed no REC jobs.

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[3] API Comments to EPA on Docket ID No. EPA-HQ-OAR-2010-0505, November 30, 2011, Page 94.

[4] API Comments to EPA on Docket ID No. EPA-HQ-OAR-2010-0505, November 30, 2011, Page 94. API estimates that emissions could be controlled from 20,000 wells/yr and there is REC capacity for 4,000 wells/yr; therefore, there is a shortfall in REC capacity of 16,000 wells/yr.

[5] ANGA comments to EPA on Docket ID No. EPA-HQ-OAR-2010-0505, November 30, 2011.

Assuming that RECs would continue at the same rate for the remaining four months of the year, an annualized REC total of 1,614 jobs was estimated by HCLLC for the purposes of this analysis.

1,076 RECs in 8 months = 1,614 RECs in 12 months

Using API's estimate of 300 REC units capable of completing 4,000 RECs per year in the U.S., and ANGA's annualized estimate of 1,614 RECs per year completed by five companies, HCLLC's calculations show that five of ANGA's member companies are using 40% of the U.S. REC capacity.

1,614 RECs per year completed by 5 companies/ 4,000 REC total U.S. current capacity = 40%

If, as ANGA postulates, all of its 30 members are completing wells using RECs at a rate of 92%, its 30-member organization alone would use all of the available U.S. REC capacity. Yet, REC use is reported by a number of companies that are not ANGA members. EPA's Natural Gas Star Program documents this REC use. Therefore, it appears that ANGA's REC use data on five of its 30 members are anomalous; these companies likely use REC methods at a higher, disproportionate rate than would be indicated across all U.S. wells.

There is insufficient U.S. equipment capacity in place to comport with ANGA's assertion that 92% of all new and recompleted wells use REC equipment. While a 92% REC equipment use rate may be true for the five companies surveyed, these data are not indicative of the national average, which EPA relies on for its rulemaking.

By comparison, API reports that approximately 70% of new shale gas well completions used REC equipment.[6] However, this number drops dramatically when conventional gas well completions and recompletions are factored into the equation. API estimates an overall 20% REC usage for well completions and recompletions including shale wells.

A 92% REC equipment use rate for all new and recompleted gas wells in the U.S. is not physically possible, because there is insufficient equipment available in the U.S. at this time to meet that demand.

API has requested that EPA delay the implementation of REC rules to provide industry with enough time to fabricate the extra 1,300 REC units that are needed to meet current and future REC demand.[7] API acknowledges there is a substantial inventory of eligible gas well REC candidates that are not implementing emission control due to the lack of available equipment. API's conclusion that there is a substantial shortfall in REC equipment capacity in the U.S. is discordant with ANGA's conclusion that 92% of well completions are controlled using REC equipment.

API points out that without EPA rulemaking, voluntary investment in REC equipment fabrication is unlikely. API's conclusion supports the need for mandatory rulemaking to fuel investment in manufacturing the 1,300 REC units needed by industry.

> *A related problem with meeting the equipment demand is the availability of capital to fund the necessary new equipment given the current economic conditions and credit availability. Manufacture of a single set of high-pressure code compliant REC equipment is expected to cost about $467,000 per set. With the estimated 1,300 additional sets*

[6] API Comments to EPA on Docket ID No. EPA-HQ-OAR-2010-0505, November 30, 2011, Attachment G, p.3
[7] API Comments to EPA on Docket ID No. EPA-HQ-OAR-2010-0505, November 30, 2011, Page 32.

> *necessary this implies a capital investment in excess of $600 MM to manufacture the equipment.* ***The majority of the pressure vessel manufacturers are not large companies and will likely not commit the capital and effort to expanding the equipment base until the rule is finalized and detailed requirements are known****.*[8]

API does not comment on the financial capacity of the gas exploration companies themselves to fund REC equipment fabrication. . An accelerated timeframe for EPA's rulemaking may be possible if gas exploration companies fund the investment in REC equipment, rather than relying small companies to take the financial risk prior to a final rule being issued.

> API advises EPA that 1,300 additional REC units are needed to capture emissions from all well completions eligible for REC controls. API states that rulemaking will be required to prompt REC investment. API's conclusion that there is a 1,300 REC unit shortfall is discordant with AGNA's position that 92% of all completions use REC equipment.

There are two important questions to raise about ANGA's URS study:

1. Is the data statistically significant? In other words, can the conclusions reached using the limited dataset in the study be extrapolated across all U.S. wells?
2. Is there sufficient REC equipment capacity in the U.S. to meet URS' 92% REC estimate?

ANGA's data is not statistically significant on a national scale. ANGA collected data from seven of 30 member companies on 1,174 wells; in the U.S. more than 490,000 gas wells exist and more than 27,000 new gas wells are drilled each year. ANGA's data do not reflect operations in all gas producing states. ANGA's data only represent 0.2% of all U.S. gas wells and 4.3% of all new wells.

1,174 wells in ANGA URS Study/ 490,000 U.S. gas wells = 0.2%
1,172new wells in ANGA URS Study/ 27,000 new U.S. gas wells = 4.3%

> ANGA's data only represent 0.2% of all U.S. gas wells and 4.3% of all new gas wells drilled each year.

ANGA has 30 member companies[9] comprised mainly of independent oil and gas exploration and production companies. Many of ANGA's member companies are focused on new shale gas development, as evidenced by Figures 4 and 5 in URS' study showing that the 1,174 well data set primarily correlates to new drilling associated with shale gas plays.

EPA reports that there are 95 large and 6,329 small oil and gas exploration and production companies operating in the U.S. for a total of 6,424 companies.[10] The data URS collected on 1,174 wells from seven of ANGA's member companies reflects only 0.1% of U.S. oil and gas exploration and production companies, and 7% of large companies.

7 ANGA companies in URS dataset/ 6,424 U.S. E&P companies = 0.1% of all U.S. E&P companies
7 ANGA companies in URS dataset/ 95 large U.S. E&P companies = 7% of large U.S. E&P companies

[8] API Comments to EPA on Docket ID No. EPA-HQ-OAR-2010-0505, November 30, 2011, Pages 94-95.

[9] http://www.anga.us/about-us/our-members

[10] EPA, Regulatory Impact Analysis, Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry, July 2011, p. 2-38.

URS data represents 0.1% of all U.S. E&P companies and 7% of large U.S. E&P companies.

Therefore, HCLLC concludes that it is not appropriate to extrapolate URS' limited dataset to the entire U.S. gas industry.

API reports that 80% of the natural gas wells (exploration and production wells) drilled in the next decade will be hydraulically fractured.[11]

The Energy Information Administration (EIA) reports that between 2005 and 2010, on average, 27,228 gas wells were drilled per year (Table No.1), including 2,043 exploration wells and 25,185 production wells. API has consistently maintained that it will not be possible to implement RECs on most exploration wells and some production wells.

Table No. 1: Percentage of Wells Using Reduced Emission Completions								
	Number of Gas Wells Drilled						Average	80% of wells Hydraulically Fractured (using API assumption)
Gas Well Type	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**		
Exploration	2,141	2,455	2,796	2,445	1,266	1,156	2,043	1,635
Development	26,449	30,316	30,057	30,447	17,626	16,215	25,185	20,148
Total	**28,590**	**32,771**	**32,853**	**32,892**	**18,892**	**17,371**	**27,228**	**21,783**
Number of Gas Wells Drilled from EIA Data: Crude Oil and Natural Gas Exploratory and Development Well Data								
API estimates 80% of gas wells will be hydraulically fractured.								

Therefore, for the purposes of this analysis, HCLLC used API's 80% hydraulic fracturing assumption multiplied only by the projected number of new production wells (25,185) to estimate the number of new gas wells per year that could potentially require a REC. HCLLC did not include the 2,043 exploration wells because they are typically ineligible for RECs.

(25,185 production wells drilled) x (80% HF) = 20,148 production well REC candidates

If, as ANGA postulates, 92% of all new wells in the U.S. use REC methods, then 18,536 REC jobs would currently be completed annually.

(20,148 total production well REC candidates) x (92% ANGA assumption) = 18,536 REC jobs

Yet, both API and EPA report that currently the U.S. only has a maximum capacity of 4,000 REC jobs per year.

Therefore, ANGA's 92% REC use estimate cannot be accurate on a national scale, unless both API's and EPA's estimates of a 4,000-REC job capacity is incorrect. Instead, it appears that the data provided by seven ANGA member companies are indicative of independent companies that aggressively drill shale gas plays.

[11] http://www.api.org/policy/exploration/hydraulicfracturing/questions_answers.cfm.

If API's and EPA's estimates of a 4,000-REC unit capacity are correct, and if REC units are only used on new wells, and not allocated to the recompletion of existing wells, then only 20% of new wells could currently use RECs.

4,000 REC capacity/ 20,148 REC jobs needed = 20% of wells use REC

Of note, this estimate is a very conservative because companies report to EPA Natural Gas STAR that REC units are, in fact, allocated to recompletions. Therefore, EPA's estimate of 14-19% is on the conservative end of the spectrum.

Question No. 2: EPA estimated that 9,175 Mcf total gas/REC (8,258 Mcf methane/REC) could be recovered using a REC, whereas ANGA assumes 765 Mcf/REC. Is EPA's 9,175 Mcf /REC estimate well supported?

ANGA states that EPA's 9,175 Mcf estimate is not representative of the amount of gas that is typically captured during a REC. ANGA asserts that EPA has overestimated the amount of gas recovered by 1200%, and the actual gas volume recovered during a REC is typically 765 Mcf.[12] Incongruously, ANGA reaches this conclusion by relying on gas flow rate data from 98 wells that were determined to be ineligible for RECs.

ANGA's 765 Mcf assumption is based on a 2011 URS study that examined the gas flow rate from 98 wells that were determined to be ineligible for RECs (cases where gas was either flared or vented). While this same 2011 URS study collected data on 1,076 wells that used REC equipment, URS did not report the amount of gas collected by any of the 1,076 REC jobs in its study.

Wells that are not eligible for RECs are commonly low flowrate and low pressure wells, or wells where nearby pipeline infrastructure has not yet been installed. Therefore, by definition, ineligible wells would not be representative of the higher gas flow rate and higher gas pressure wells that would typically use REC equipment.

URS' study only provided data on the flowback duration of wells that used RECs. URS estimates a 5.8 day duration for the average REC job.

API concurs with EPA's estimate of a 3-10 day REC duration, suggesting 7 days as a reasonable average based on its dataset.[13] ANGA's estimate of 5.8 days compares favorably with EPA's estimate of 3-10 days and API's estimate of 7 days.

ANGA's use of a 765 Mcf/REC gas estimate is based on wells that were ineligible for RECs and is not representative of the higher gas flow rate and higher pressure gas wells that would typically use REC equipment.

ANGA's recommendation to use a 765 Mcf estimate for gas produced from a new well during a REC is not supported by the national gas production data shown in Table No. 2 on the following page.

[12] ANGA comments to EPA on Docket ID No. EPA-HQ-OAR-2010-0505, November 30, 2011, including URS Study attached dated November 28, 2011.

[13] API Comments to EPA on Docket ID No. EPA-HQ-OAR-2010-0505, November 30, 2011, Attachment G, p.3.

Table No. 2: 2009 EIA Data on Distribution of Wells by Production Rate Bracket				
	Number of Gas wells	Annual Gas Production (Bcf)	Gas Rate per Well per Day (Mcf/day)	Estimated Gas Rate Per Well Using ANGA's 5.8 day estimate per REC (Mcf/REC)
EIA reports 378,579 wells in the U.S. that produce less than 765 Mcf over a 5.8 day period	91,005	73	2	14
	45,034	131	8	48
	60,930	358	17	96
	43,009	428	28	162
	32,564	458	39	229
	24,829	451	51	295
	18,967	421	62	360
	21,718	591	76	442
	23,974	841	99	571
	16,539	744	127	734
Subtotal	**378,569**			
EIA reports 82,819 wells in the U.S. that produce more than 765 Mcf over a 5.8 day period	11,638	645	157	909
	16,083	1,122	197	1,145
	9,959	896	256	1,482
	22,546	3,157	403	2,336
	13,444	3,520	782	4,538
	5,528	2,572	1,545	8,962
	2,038	1,708	3,008	17,446
	816	1,342	6,039	35,028
	460	1,633	11,908	69,064
	247	1,913	22,918	132,922
	51	725	46,469	269,517
	9	228	84,082	487,675
Subtotal	**82,819**			
EIA reports the average U.S. Gas Rate per Well is 148.5 Mcf/day				
Total	**461,388**	**-**	**148.5**	

* EIA Data: Natural Gas Annual Supply & Disposition by State

Table No. 2, developed by HCLLC using 2009 EIA data, shows that the national average gas production rate per gas well was 148.5 Mcf/day. Multiplying the average gas well rate by ANGA's estimate of 5.8 days per REC job yields an average gas rate in the U.S. of 861 Mcf/REC per well.

(148.5 Mcf/day average gas rate per U.S. well) x (5.8 days per REC) = 861 Mcf per REC

However, REC equipment is not used or targeted to the average aging U.S. gas well. Instead, EPA proposes that REC equipment be used on new well completions and recompletions of existing wells. The gas flow rate of new well completions and recompleted wells is several orders of magnitude larger than the average U.S. gas well flow rate; otherwise, the economics of drilling a new gas well or recompleting a well would not be supported.

As shown in Table No. 2, there are 82,819 wells in the U.S. that produce gas at flow rates exceeding 765Mcf over a 5.8 day REC job period. Due to limited equipment supply, the highest flow rate gas wells are prioritized for RECs. This means the average gas flow rate per REC substantially exceeds 765 Mcf over a 5.8 day REC job period.

Table No. 2 includes a wide range of well ages and gas flow rates, from decades old, low pressure, low flow rate wells to newly drilled wells. Less than 6% of the data in Table No. 2 is from newly drilled wells. Therefore, a 765 Mcf/REC estimate represents a marginal well, not the type of well that is prioritized for a REC.

Additionally, API and EPA point out there is only REC capacity for 15-20% of the eligible wells. Therefore, with a limited current equipment inventory of up to 4,000 jobs per year, or potentially as high as 20,000 jobs per year in the future, the wells prioritized for REC jobs would substantially higher than 765 Mcf/REC to which optimize the rate of return. Operators would not allocate a limited REC equipment supply to average producing gas well.

For example, a technical paper found on ANGA's website[14] prepared by Carnegie Mellon University uses an average well gas production rate of 300-10,000 Mcf/day for a newly drilled Marcellus Shale well. Using ANGA's recommended REC duration rate of 5.8 days and the Carnegie Mellon University estimate results in a 1,740-58,000 Mcf gas recovery rate. This calculation is much more representative of the current gas well using a REC than 765 Mcf/REC. Of note, Carnegie Mellon University's low-side estimate of 300 Mcf/day is based on an average gas production rate for a well over a 25-year duration. It does not take into account that flow rates peak during the first year of a well's life – the period when RECs are implemented.[15] Therefore, Carnegie Mellon University's analysis shows that a REC on a new Marcellus Shale gas well would substantially exceed 1,740 Mcf.

API's comments on EPA's Regulatory Impact Analysis for the proposed NSPS rulemaking also question EPA's use of 9,175 Mcf/REC (8,258 Mcf methane/REC). API states that this higher gas rate is indicative of higher profitability REC jobs that are currently receiving priority due to the limited REC equipment inventory.[16] API explains that when a larger REC equipment fleet is available, the amount of gas recovered per REC will decline, as less economic jobs are completed. Yet, even at lower gas flow rates, RECs are still predicted to be economical. API's main concerns are the time required to build REC units the potential for a mandatory REC requirement to slow the drilling and workover pace until sufficient REC units are constructed.

API does not contest EPA's use of 9,175 Mcf/REC (8,258 Mcf methane/REC) for rulemaking purposes, and instead attaches an independent engineering review completed by David Simpson that concludes:

> *…we assumed that the EPA estimate of 1.2 MMcf/day and 7 days of flowback (8,400 Mcf per REC) are as reasonable an estimate as anyone is likely to develop.*[17]

Simpson explains that EPA's use of 1,200 Mcf/day (over a 7 day period), for a total of 8,400 Mcf/REC is reasonable because most pipeline gathering systems require a 1,200-1,400 Mcf/day gas flow rate (to flow into the pipeline without additional gas compression equipment).[18]

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[14] http://www.anga.us/media/229762/life%20cycle%20greenhouse%20gas%20emissions%20of%20marcellus%20shale%20gas%20-%20carnegie%20mellon.pdf.

[15] Jiang, M., Griffin, E.M., Hendrickson, C., Jaramillo, P., VanBriesen, J. and Venkatesh, A., Life Cycle Greenhouse Gas Emissions of Marcellus Shale Gas, Carnegie Mellon University, August 5, 2011, p.4.

[16] API Comments to EPA on Docket ID No. EPA-HQ-OAR-2010-0505, November 30, 2011.

[17] API Comments to EPA on Docket ID No. EPA-HQ-OAR-2010-0505, November 30, 2011, Attachment G, p. 6.

[18] API Comments to EPA on Docket ID No. EPA-HQ-OAR-2010-0505, November 30, 2011, Attachment G, p. 4 and 6.

For example, industry data provided to Colorado during the development of Colorado's REC Rule 805 (otherwise known as "Green Completion Rule 805") argued that most gas wells producing less than 500 Mcf/day would not be good candidates for REC, unless compression is added to overcome pipeline backpressure. In response to industry' s technical arguments, Colorado limited Rule 805 to require RECs for wells with a gas flow rate of 500 Mcf/day or more.[19]

Therefore, ANGA's position that the average REC job only produces 765 Mcf over a 5.8 day period (132 Mcf/day) is inconsistent with the industry data provided to Colorado showing that a minimum gas flow rate of 500 Mcf/day is required for most RECs. It is also inconsistent with API's data showing that a gas rate of 1,200-1,400 Mcf/day is required for most RECs.

The gas flow rate of 765 Mcf/REC estimated by ANGA is clearly under-predicted. Wells prioritized for REC use would substantially exceed 765 Mcf. The amount of gas produced though a REC unit can be measured by a gas flow meter. It is recommended that ANGA collect data on the amount of gas actually collected during REC jobs and provide that data to EPA.

Question No. 3: In 2011 IHS CERA examined EPA's estimate of 9,175 Mcf/REC. Does EPA's 9,175 Mcf/REC (8,258 Mcf methane/REC) estimate have a technical basis?

In 2001, EIA reported that initial gas flow rates from all U.S. wells completed in 1996-2000 was 1,900 Mcf/day/completion.[20] Using the 1,900 Mcf/day/completion estimate and ANGA's assumed 5.8 day REC duration period results in an estimate of 11,020 Mcf of gas recovered per REC. This calculation compares favorably with EPA's estimate of 9,175 Mcf of gas recovered per REC. Of note, EIA's 2001 data is based on new U.S. gas well flow rates and does not include the more recent surge in shale gas wells that produce high initial gas rates.

$$(1{,}900\ \text{Mcf/day/completion}) \times (5.8\ \text{days/REC}) = 11{,}020\ \text{Mcf/REC}$$

Additionally, API's comments to EPA support EPA's use of 1,200 Mcf/day (over a 7 day period), for a total of 8,400 Mcf/REC as reasonable estimate.[21]

EPA estimates the cost of a REC job to be $33,237.[22] Using a conservative gas price of $4/Mcf, a gas rate of 1,433 Mcf/day/completion would be required to breakeven. Since the average gas rate of 1,900 Mcf/day/completion reported by EIA exceeds the breakeven threshold of 1,433 Mcf/day/completion, the average REC job is predicted to be economic. With a limited equipment supply, the economics of a prioritized well would even be more robust.

$$(\$33{,}237/\text{REC job})/(\$4/\text{Mcf}) = 8{,}309\ \text{Mcf}$$
$$(8{,}309\ \text{Mcf})/5.8\ \text{days per well completion} = 1{,}433\ \text{Mcf/day/completion}$$

[19] Colorado Oil and Gas Conservation Commission, Rule §805(b)(3).

[20] U.S. Energy Information Administration (EIA), U. S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply, http://www.eia.gov/oiaf/servicerpt/natgas/boxtext.html.

[21] API Comments to EPA on Docket ID No. EPA-HQ-OAR-2010-0505, November 30, 2011, Attachment G, p. 4 and 6.

[22] EPA, Technical Support Document for Standards of Performance for New Stationary Sources: Oil and Natural Gas Production and Natural Gas Transmission and Distribution; National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities; and National Emission Standards for Hazardous Air Pollutants From Natural Gas Transmission and Storage Facilities, Docket ID No. EPA-HQ-OAR-2010-0505, 2011, p. 125 of 604.

Data published by ALL Consulting in 2008 show that the average gas rate for shale gas wells in the U.S. ranges from 100 Mcf/day to 3,100 Mcf/day.[23] The low end of the range is based on the Lewis Shale. If the Lewis Shale is excluded, the next lowest gas flow rate is the Woodford Shale at 415 Mcf/day. Lewis Shale wells are unlikely to be candidates for RECs because of low flow rates and pressures; therefore, a range of 415 Mcf/day to 3,100 Mcf/day is evaluated below. Using the 415 Mcf/day to 3,100 Mcf/day estimate and ANGA's assumed 5.8 day REC duration period results in an estimate of 2,407-17,980 Mcf recovered per REC. ALL Consulting's data compares favorably with EPA's estimate of 9,175 Mcf recovered per REC.

(415 Mcf/day/completion) x (5.8 days/REC) = 2,407 Mcf/REC
(3,100 Mcf/day/completion) x (5.8 days/REC) = 17,980 Mcf/REC

A Simmons & Co. International Report titled U.S. Threshold Gas Prices - Determining Prices Required to Sustain Drilling Key U.S. Gas Plays included data on initial gas production rates.[24] Simmons & Co. International reported the following:

- **Conventional gas wells:** 4,000 Mcf/day rising to 7,000 Mcf/day after well cleanup; producing 5.664 Bcf over 5.25 years on average. Offshore well data was substantially higher at 15,000 Mcf/day climbing to 23,500 Mcf/day after well cleanup.

- **Tight Gas Sand Wells:**
  - Piceance Basin of Western Colorado has a typical initial rate of 1,200 Mcf/day
  - Lobo Trend in South Texas has typical initial rate of 3,000 Mcf/day
  - Uinta Basin of Utah has a typical initial rate of 1,500 Mcf/day

Therefore Simmons & Co. International data shows that even new conventional wells and tight gas sand wells typically produce 1,200 Mcf/day to 15,000 Mcf/day.

(1,200 Mcf/day/completion) x (5.8 days/REC) = 6,960 Mcf
(7,000 Mcf/day/completion onshore wells) x (5.8 days/REC) = 40,600 Mcf

Data from two independent consultants and the EIA confirm that the typical gas production rate ranges from 2,407 Mcf/REC to 40,600 Mcf/REC.

Please let me know if you have any questions on this memo.

Susan L. Harvey
Susan L. Harvey

[23] ALL Consulting, Hydraulic Fracturing Considerations for Natural Gas Wells of the Fayetteville Shale, 2008, p. 5.
[24] http://www.epmag.com/archives/newsComments/6242.htm#

Exhibit 1 – Reference Materials

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coalbed methane reservoirs from the requirements for subcategory 1 wells.

Of the 25,000 new and modified fractured gas wells completed each year, we estimate that approximately 3,000 to 4,000 currently employ reduced emission completion. We expect this number to increase to over 21,000 REC annually as operators comply with the proposed NSPS. We estimate that approximately 9,300 new wells and 12,000 existing wells will be fractured or refractured annually that would be subject to subcategory 1 requirements under the NSPS. We believe that there will be a sufficient supply of REC equipment available by the time the NSPS becomes effective. However, energy availability could be affected if a shortage of REC equipment was allowed to cause delays in well completions. We request comment on whether sufficient supply of this equipment and personnel to operate it will be available to accommodate the increased number of REC by the effective date of the NSPS. We also request specific estimates of how much time would be required to get enough equipment in operation to accommodate the full number of REC performed annually.

In the event that public comments indicate that available equipment would likely be insufficient to

F.N. #2

Table 3-5 Estimates of Control Unit-level and National Level Natural Gas and Condensate Recovery, NSPS Options, 2015

Source/ Emissions Points	Emissions Control	NSPS Option	Projected No. of Affected Units	Unit-level Product Recovery: Natural Gas Savings (Mcf/unit)	Unit-level Product Recovery: Condensate (bbl/unit)	Total Product Recovery: Natural Gas Savings (Mcf)	Total Product Recovery: Condensate (bbl)
Well Completions							
Hydraulically Fractured Gas Wells	REC	1, 2, 3	9,313	8,258	34	76,905,813	316,657
Hydraulically Fractured Gas Wells	Combustion	1, 2, 3	446	0	0	0	0
Hydraulically Fractured Gas Wells (existing wells)	REC	2, 3	12,050	8,258	34	99,502,875	409,700
Equipment Leaks							
Well Pads	NSPS Subpart VV	3	4,774	386	0	1,840,377	0
Gathering and Boosting Stations	NSPS Subpart VV	3	275	1,472	0	404,869	0
Processing Plants	NSPS Subpart VVa	2, 3	29	2,819	0	81,750	0
Reciprocating Compressors							
Gathering/Boosting Stations	AMM	1, 2, 3	210	397	0	83,370	0
Processing Plants	AMM	1, 2, 3	375	1,079	0	404,677	0
Trans. Compressor Stations	AMM	1, 2, 3	199	1,122	0	223,374	0
Underground Storage Facilities	AMM	1, 2, 3	9	1,130	0	9,609	0
Centrifugal Compressors							
Processing Plants	Dry Seals/Route to Process or Ctrl	1, 2, 3	16	11,527	0	184,435	0
Trans. Compressor Stations	Dry Seals/Route to Process or Ctrl	1, 2, 3	14	5,716	0	80,018	0
Pneumatic Controllers -							
Oil and Gas Production	Low Bleed/Route to Process	1, 2, 3	13,632	386	0	5,254,997	0
Natural Gas Trans. and Storage	Low Bleed/Route to Process	1, 2, 3	67	0	0	0	0
Processing Plants	Instrument Air	1, 2, 3	15	871.0	0	13,064	0
Storage Vessels							
High Throughput	95% control	1, 2, 3	304	146	0	44,189	0
Option 1 Total (Mcf)						**83,203,546**	**316,657**
Option 2 Total (Mcf)						**182,788,172**	**726,357**
Option 3 Total (Mcf)						**185,033,417**	**726,357**

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Guidance" revised March 2010[J] was approved until permits were issued for reduced emissions completions to give all companies time to acquire the needed equipment and train operators on doing the completions for only part (concentrated development areas and the Jonah Pinedale Development Area) of the State of Wyoming. With the nationwide coverage of Subpart OOO the magnitude of the gap between current availability and necessary equipment and experienced personnel will be much larger and a longer delay will be required.

15.4.1. Availability of Equipment

With implementation of the rule required so quickly after the rule is finalized, equipment will not be available to meet these requirements. There is already a shortage of the specialty equipment required due to the recent WYDEQ BACT Policy and the expansion of the rule to all of the US will make this shortage unmanageable. It will take a significant amount of time for the vessel/equipment manufacturers to expand their capacity to manufacture adequate equipment which meets API and pressure-vessel code specifications in the quantities required to comply with the rule. Maintaining the current aggressive rule implementation schedule will force one of two outcomes:

(1) The pace of drilling of new wells and recompletion of existing wells will be sharply reduced which will result in job losses, supply disruption, higher natural gas prices, and higher electricity prices.

(2) In order to comply, companies will be forced to use or quickly manufacture/modify equipment which may not meet fabrication codes and standards and could be less safe to use.

In short, the current schedule contemplated by the rule is very likely to unnecessarily create unsafe conditions and operations or supply disruptions and job losses.

Today there is something on the order of 300 sets of REC equipment in existence. This equipment has the ability to process approximately 4,000 wells a year. To allow 20,000 wells to flow to sales in a year would require about 1,300 additional sets of equipment. This equipment is fairly specialized, the shops licensed to make it are limited, and some of the components require a long lead time. It should be expected with today's demand for other pressure vessels that it will be on the order of one year before the first set of additional equipment can be delivered. From that point, industry can probably deliver about 50 sets per quarter, so about 7.5 years will be required to meet the anticipated demand. For this reason, API also requests that the applicability be further limited and that the specific equipment not be specified as discussed further below. As discussed in Section 7.4, if the equipment is not available it does not constitute "the best system of emission reduction."

A related problem with meeting the equipment demand is the availability of capital to fund the necessary new equipment given the current economic conditions and credit availability. Manufacture of a single set of high-pressure code compliant REC equipment is expected to

[J] Wyoming Department of Environmental Quality, Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance, Revised March 2010, http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf

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Summary of Results

For non-green completions, data was summarized by basin, and then the basins were averaged to produce a national average value. As can be seen in the following attached table, the resulting non-green completion flowback rate, using EPA's methodology, was 765 Mscf of gas. This is only a small fraction (8%) of the 9175 Mscf of gas per flowback that EPA had used as a basis for the subpart quad O - Oil and Natural Gas Air Pollution Standards. There was variability among the basins, which had averages ranging from 340 Mscf to 1160 Mscf. However, all of these averages, and in fact the individual company averages, which ranged from 443 to 1455 Mscf, are far below EPA's assumed value.

The percent of wells in the dataset that were green completions was 92% of 2011 well completions. Even among the 8% that were non-green completed, 55% of those were flared (rather than directly vented). This leaves approximately 4% of the well completions in the dataset that were uncontrolled. This is far lower than EPA's assumed value of 85% of the completions that are uncontrolled, with only 15% being green completed. EPA had also assumed 50% were flared.

The average duration of non-green completions in the dataset was 3.5 days (a histogram of duration distribution is shown), and the average duration of a green completion in the dataset was 5.8 days (again, a histogram of duration distribution is shown). EPA had assumed flowback duration of 3-10 days, but the dataset shows the non-green completions to be much shorter. Only the green completions cover the 3-10 day span that EPA had assumed.

Conclusions

While the dataset is limited to seven companies and just under 1200 wells, there is a reasonable representation across many of the unconventional gas development regions that are being developed in the United States. The attachment shows 2 maps of the locations of the wells in this dataset by AAPG basin. A comparative map from the Energy Information Administration of US Shale gas plays demonstrates a good overlap with many of those developing areas.

It appears that the EPA's 9175 Mscf/completion event for unconventional fractured wells is potentially overestimated by 1200%. The ANGA data may not be robust enough to provide a definitive new national flowback emission factor because of its reliance on conservative assumptions and limited regional data. However it is far more current, and certainly collected on a far more consistent and transparent basis than any of the data EPA used to generate its 9175 Mscf. According to the Technical Support Document (TSD) for Subpart W of the EPA's GHG Mandatory Reporting Rule the 9175 Mscf was based upon some presentations by companies at

F.N. #6

Attachment G

Review of the Regulatory Impact Analysis (RIA) for the Well Completions Portion of the Proposed New Source Performance Standards for the Oil and Natural Gas Industry

By David A. Simpson, PE

EPA has proposed under 40 CFR 60.5375 that "*Except as provided in paragraph (f) of this section, for each well completion operation with hydraulic fracturing, as defined in §60.5430, you must control emissions by the operational procedures found in paragraphs (a)(1) through (a)(3) of this section.*

(1) You must minimize the emissions associated with venting of hydrocarbon fluids and gas over the duration of flowback by routing the recovered liquids into storage vessels and routing the recovered gas into a gas gathering line or collection system.

(2) You must employ sand traps, surge vessels, separators, and tanks during flowback and cleanout operations to safely maximize resource recovery and minimize releases to the environment. All salable quality gas must be routed to the gas gathering line as soon as practicable.

(3) You must capture and direct flowback emissions that cannot be directed to the gathering line to a completion combustion device, except in conditions that may result in a fire hazard or explosion. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback."

API conversations with Halliburton, Schlumberger, and BJ Services (the three largest oilfield service companies) and Aztec Well Services, a regional drilling company, indicates that essentially every well that is drilled is evaluated for hydraulic fracture stimulation and has been for many years. There are fields where this evaluation results in different stimulation techniques, but these fields are reasonably rare. Consequently, the population for this requirement is approximately every gas well.

To support these conversations, the online databases for Colorado[1], New Mexico[2], and Wyoming[3] were searched for information on hydraulic fractures. Permit data is stored as scanned images and a review of a random selection of wells completed since 1960, showed that the data is mostly silent on stimulation techniques, but where such techniques were mentioned every well that was looked at had been hydraulically fractured regardless of the formation.

Companies Affected: Data from IHS for 2008 showed that there were 14,289 companies with at least one producing well[4]. There were 5,873 companies with 10 or more producing wells. RIA Table 7-18 claims that this number is 128 companies. While there are a smaller number of companies that are drilling new wells, all of these companies will be subject to this rule.

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[1] Website of Colorado database http://cogcc.state.co.us/

[2] Website of New Mexico database http://octane.nmt.edu/gotech/Petroleum_Data/General.aspx

[3] Website of Wyoming database http://wogcc.state.wy.us/

[4] Reference for IHS company data http://www.ihs.com/products/oil-gas-information/production-data/

Company Survey: API asked member companies to provide information about their 2012 development plans. Nine companies provided data on 29 producing areas where they expected to drill 6,159 wells in 2012. The companies that responded represented all of the largest producers in the major shale-gas plays[5], so it is likely that this survey encompassed a significant portion of the Shale-gas development for 2012. Extrapolating the data to the population of companies is difficult and of limited value, but the best we were able to do is predict that 30% of the 2012 drilling will be shale-gas, 70% will be CBM, tight-gas, and conventional. Table G-1 summarizes the results of the API survey. Within a single play with several companies reporting, the variability was significant. The only conclusion that can be drawn is that each company has their own strategy for performing reduced emissions completions (REC) and the equipment required (and its cost and supplier) reflects that variability. A weighted average of this data puts the cost/day very close to $5,000.

Table G-1: Summary of API Survey Results

Type Reservoir	2012 Well Count	Minimum Reported Cost/day	Maximum Reported Cost/day
Conventional REC	1,060	$2,150	$5,900
CBM REC	625	$4,286	$30,000
Shale REC	2,698	$1,530	$10,500
Tight Gas REC	74	$6,000	$15,000
Non-REC	1,702		

Applicability of Reduced Emissions Completions (REC): The Table 3-2 of the RIA expects that 9,313 wells will meet the requirements for REC in 2015 (out of 17,453 new gas wells). In the same table they expect that there will be 12,050 refracs that meet the criteria for REC and 42,352 conventional wells that will not meet the criteria. The benefits of REC stated in the RIA depend heavily the data contained in EPA's Natural Gas Star Program.

First, the data within the Natural Gas Star Program has been carefully selected initially by the contributing company and finally by the EPA itself to present environmental successes in the best possible light. The success stories described within the program represent techniques that have worked on the projects referenced, and contributing companies have not claimed that the techniques reported are in any way universally applicable to the industry. In fact, the Natural Gas Star Partner reported successes for reduced emission completions have been targeted to specific areas where the reservoir characteristics and infrastructure enable reduced emission completions. The limitations on use of reduced emission techniques have been clearly articulated and communicated to EPA, both through the Natural Gas Star Program and in various other communications. To ignore these limitations and assume that a few dozen

[5] Companies responding were Anadarko Petroleum Corp, BP Production Co, Chesapeake Energy Corp., Chevron Corp., ConocoPhillips, Devon Energy, Noble Energy Inc., Shell, Talisman Energy Inc., and XTO Energy

or even a few hundred successful reduced emissions completions means that 53% of all completions, frac's, and re-frac's will benefit from this technique is extrapolating a limited data set far outside the parameters supported by the original sample size.

The technical support document (TSD) for reduced emissions completions relied heavily on data from the Wyoming Department of Environmental Quality (WYDEQ) Air Quality Division and claimed that "The State of Wyoming's Air Quality Division (WAQD) requires operators to complete wells without flaring or venting where the following criteria are met: (1) the flowback gas meets sales line specifications and (2) the pressure of the reservoir is high enough to enable REC. If the above criteria are not met, then the produced gas is to be flared". According to the WYDEQ's March 2010 Oil and Gas Production Facilities Permitting Guidance [6] this is a requirement in only 7 counties of the state.

Second, the number of refracs is assumed to be 10% of the population of gas wells each year. Data from industry puts that number well under 1%.

Third, the requirements for REC are: (1) that any gases used in the frac will decline to acceptable levels for sales gas before the end of the flow back; and (2) that the well has adequate reservoir pressure to flow at rates adequate for transporting solids and liquids into an imposed back pressure. The first requirement is easily satisfied for hydraulic fracture stimulations using a liquid as the carrier fluid—the large number of procedures that use nitrogen or CO_2 foam will never meet the requirements during the flowback period. The second requirement is very dependent on reservoir pressure and line pressure. The industry direction is to flow to sales if it is cost effective, but many wells will not clean up at observed pressures.

The TSD estimates that wellsite dehydrators and sand separators are "often" included on completions and that "many" REC wellsites will only add $806/day (2006 estimate inflated to 2008) to the cost of completion. On sites that have to bring in temporary equipment this number increases to $7,486 (2008 dollars) per day. They further claim that flowbacks will be done in 3-10 days (average of 7 days) and that an average incremental cost is $4,146/day. This includes a one-time cost of $691 for transportation, placement, and removal of equipment. This results in a total cost of $29,713/well.

The companies who responded to API's survey described above represented the majority of the most active shale-gas operators. This group of companies is doing REC on approximately 70% of the wells they reported. This data is very much skewed toward shale-gas. Evaluating the companies that responded to the survey relative to the population of companies in the industries indicates that the industry will likely drill 30% shale gas and 70% CBM, tight-gas, and conventional wells. Data from the API member survey showed that the average cost per day is about $5,000 (reasonably close to the EPA estimate). The EPA estimated that flow back periods will typically be 3-10 days with 7 being a reasonable average. The API survey is largely in agreement with those estimates. The problem is that the equipment does not magically appear on day one and instantly disappear on day 7. It has to be staged before the flowback can be scheduled, gas control must have advance notice to nominate the gas to the gathering system, and some contingency time is generally needed. Then at the end of the flowback, crews must be scheduled to demobilize the equipment, trucks must be scheduled to pick it up, and it has to have a place to go. The front-end/back-end non-productive time must be paid for. To account for this, the

[6] Wyoming Department of Environmental Quality, Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance, Revised March 2010, http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf

majority of flowback companies have a 30 day minimum rental period which makes the average cost per well $150,000 plus $30,000 for mobilization/demobilization for an average total of $180,000. Also, the API Survey reported that the storage vessels and combustion equipment for REC costs on the order of $2,000/day, but again requires a 30 day commitment so the rental cost per well is $60,000 and the mobilization/demobilization costs are $30,000.

In the TSD, the authors consistently claim that REC is only applicable to unconventional gas, then on page 4-16, they claim that every completion will recover 34 bbl of condensate at a value of $70/bbl which adds $2,380 to the benefit of REC—but most unconventional wells produce no condensate. They also assume that each well will recover 8.258 MMSCF during the flowback. This says that for a 7 day average flowback, wells will average 1.2 MMSCF/day. For the wells that can flow to sales, this is a reasonable assumption since only the strongest formations will be able to flow to sales.

The number of wells that can successfully be cleaned up by flowing into a gathering system is closer to 30% or 5,230 wells instead of 9,313. Evaluating reservoir pressure requirements to flow into typical gathering systems, a number around 1.2-1.4 MMCF/d is reasonable. However, the condensate recovery factor is unreasonably high. This leads to the cost per REC shown on Table G-2.

Table G-2: Cost per REC

	RIA	API Survey
Rental cost of equipment	$29,022	$150,000
Variable cost per installation	$691	$30,000
Total cost per job	$33,239	$180,000
Sales recovered per job	$35,410	$32,900
Net Cost (benefit) per well	($2,171)	$147,100
Number of jobs in 2015	9,313	5,230
Total cost (benefit) in 2015 of REC	**($20.2 million)**	**$782.6 million**

EPA estimated that 53% of the wells drilled would be able to sell gas. The remainder of the population was broken into hydraulically fractured wells that could not sell gas (3%) and "conventional wells" (44%) which they mistakenly suggest are not hydraulically fractured. They estimate that the equipment and reporting requirements will add $3,523 per well to the cost of the well. However, the requirements for non-sales wells are extensive and very expensive. EPA is requiring that companies capture gas that "can not be directed to the gathering line to a completion combustion device" with a "reliable continuous ignition source". When the gas is not combustible, this will require supplemental fuel. Also, this prohibits the use of electronic igniters to minimize the use the waste of pilot gas. Furthermore, EPA is also requiring that for wildcat or delineation wells, that companies supply "the distance, in miles, of the nearest gathering line", the "latitude and longitude coordinates of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum (NAD) of

Emissions Reductions

VOC content varies from well to well, field to field, and basin to basin. With 400,000 gas wells there are 400,000 unique gas analyses that are in place at any given time. Regulations require that each of the wells will be periodically re-sampled because the mix of components in a well stream changes. The mix will change with pressure changes, temperature changes, and with changes in the portion of the reservoir that is currently available to the wellbore (which changes minute-to-minute). The VOC content of the mix of wells on production at any given time is one of the most volatile parameters in this industry. The EPA based their rule making on 7 wells out of 400,000. These 7 wells were handpicked based on parameters other than an effort to provide a random sample.

To determine the mass of VOC in any given stream, you must first determine the mass of the stream and apply the weight percent VOC to that total mass. For the tables below, we assumed that the EPA estimate of 1.2 MMCF/day and 7 days of flowback are as reasonable an estimate as anyone is likely to develop. Collapsing 20,000 flowbacks into a single number is statistically invalid, but for the sake of this discussion we will accept EPA's number.

Table 3-3 in the RIA has detailed emissions reductions for gas wells that assume 83% (by volume) Methane and 3% (by volume) VOC. These percentages are the same for all the categories of gas wells, including conventional wells and disregard the fact that a significant portion of current and future drilling is in CBM and Shale Gas plays.

An article published in *Oil & Gas Journal* March 9, 2009 titled "Compositional variety complicated processing plans for US shale gas" written by Keith A Bullin and Peter E Kroushop both of Bryan Research and Engineering had a series of tables that are summarized on Table G-5.

Table G-5: Shale Gas Composition

	C1	C2	C3+	CO2	N2	Total
Barnett Average	86.8%	6.7%	2.0%	1.7%	2.9%	100.0%
Marcellus Average	85.2%	11.3%	2.9%	0.4%	0.3%	100.0%
Fayetteville Average	97.3%	1.0%	0.0%	1.0%	0.7%	100.0%
New Albany Average	89.9%	1.1%	1.1%	7.9%	0.0%	100.0%
Haynesville Shale Average	95.0%	0.1%	0.0%	4.8%	0.1%	100.0%
Shale Gas Average	90.8%	4.0%	1.2%	3.1%	0.8%	100.0%

A similar analysis of CBM would show C2+ to be approximately zero. Adding the Shale Gas analysis to the GRI analysis provided in the docket yields Table G-6. The "tonne VOC/MMSCF" column is simply the density of the gas at standard temperature and pressure times 1,000,000 SCF. The "tonne VOC/flowback" column is the "tonne VOC/MMSCF" column times the 8.4 MMSCF which would have

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the equipment manufacturer, not the owner/operator. It is difficult for the owner/operator to be assured that he is meeting the requirements of the regulation with the equipment he purchases and installs, unless EPA allows sufficient time for the manufacturer to review the equipment design and label it as complying with the regulatory requirements of this rule.

For example, there are currently few if any manufacturer "guarantees" that continuous bleed pneumatic controllers are "low bleed" as required by proposed §60.5410(d)(3). Additionally, there are few if any continuous bleed pneumatic controllers that are even capable of a bleed rate of less than six scfh under all operating conditions. Variability in operating conditions, such as increases in instrument gas supply pressure, complicates the ability of a manufacturer to guarantee continuous bleed pneumatic controller performance.

NSPS Subpart JJJJ recognized that the manufacturers needed time to design, certify and manufacture equipment, and thus required compliance only for new sources manufactured after given manufacture dates when that equipment could reasonably be available from the manufacturer in quantities to meet the demand.

The same type of allowance provided for in NSPS JJJJ is needed in Subpart OOOO. Thus, while API believes a design verification is more appropriate for pneumatic controllers than a guarantee, we recommend that any equipment design guarantee required for pneumatic controller manufacturers be delayed by two years from the effective date of the rule. For additional discussion of the "guarantee" issue for pneumatics, please refer to Section 17.10.

A similar scenario exists for the option to have the performance test of a control device conducted by the manufacturer. The requirements in NSPS OOOO for storage tank control devices cite the performance test requirements specified in §63.772(e) of NESHAP HH, which include a provision for the performance test to be conducted by the manufacturer as specified in §63.772(h). It will obviously require considerable lead time, however, before such "manufacturer certified" control devices are readily available. We request that the effective date of the storage tank requirements under NSPS OOOO be delayed for 3 years to allow time for the specified control devices to become available.

7.4. Availability of Equipment for Reduced Emissions Completions

The equipment required for Reduced Emission Completions (REC) is not "off the shelf" equipment, but is typically custom built by the owner/operator or service company to meet the anticipated reservoir properties. Additionally, service companies would have to hire and train sufficient personnel to operate the REC equipment to meet the regulatory requirements. EPA should specify a compliance period for implementing the REC requirements that realistically accounts for the limitations on availability of equipment and trained personnel needed for widespread use of REC. Please see Section 15.4 for more detailed information, and for specific recommendations on revisions to the regulatory language. Such a compliance period is well within EPA's authority and, under the circumstances, the REC requirement cannot be justified without it.

By defining each new well as an affected facility, the proposal would cause the requirement to implement RECs to become effective industry-wide upon the effective date of the final rule. As described in Section 15.4, this means that 1,300 sets of equipment would be needed to accommodate

FN #8

Guidance" revised March 2010[3] was approved until permits were issued for reduced emissions completions to give all companies time to acquire the needed equipment and train operators on doing the completions for only part (concentrated development areas and the Jonah Pinedale Development Area) of the State of Wyoming. With the nationwide coverage of Subpart OOO the magnitude of the gap between current availability and necessary equipment and experienced personnel will be much larger and a longer delay will be required.

15.4.1. Availability of Equipment

With implementation of the rule required so quickly after the rule is finalized, equipment will not be available to meet these requirements. There is already a shortage of the specialty equipment required due to the recent WYDEQ BACT Policy and the expansion of the rule to all of the US will make this shortage unmanageable. It will take a significant amount of time for the vessel/equipment manufacturers to expand their capacity to manufacture adequate equipment which meets API and pressure-vessel code specifications in the quantities required to comply with the rule. Maintaining the current aggressive rule implementation schedule will force one of two outcomes:

(1) The pace of drilling of new wells and recompletion of existing wells will be sharply reduced which will result in job losses, supply disruption, higher natural gas prices, and higher electricity prices.

(2) In order to comply, companies will be forced to use or quickly manufacture/modify equipment which may not meet fabrication codes and standards and could be less safe to use.

In short, the current schedule contemplated by the rule is very likely to unnecessarily create unsafe conditions and operations or supply disruptions and job losses.

Today there is something on the order of 300 sets of REC equipment in existence. This equipment has the ability to process approximately 4,000 wells a year. To allow 20,000 wells to flow to sales in a year would require about 1,300 additional sets of equipment. This equipment is fairly specialized, the shops licensed to make it are limited, and some of the components require a long lead time. It should be expected with today's demand for other pressure vessels that it will be on the order of one year before the first set of additional equipment can be delivered. From that point, industry can probably deliver about 50 sets per quarter, so about 7.5 years will be required to meet the anticipated demand. For this reason, API also requests that the applicability be further limited and that the specific equipment not be specified as discussed further below. As discussed in Section 7.4, if the equipment is not available it does not constitute "the best system of emission reduction."

A related problem with meeting the equipment demand is the availability of capital to fund the necessary new equipment given the current economic conditions and credit availability. Manufacture of a single set of high-pressure code compliant REC equipment is expected to

[3] Wyoming Department of Environmental Quality, Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance, Revised March 2010, http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf

cost about $467,000 per set. With the estimated 1,300 additional sets necessary this implies a capital investment in excess of $600 MM to manufacture the equipment. The majority of the pressure vessel manufacturers are not large companies and will likely not commit the capital and effort to expanding the equipment base until the rule is finalized and detailed requirements are known. Even when the rule is finalized, detailed requirements known, and manufacturers chose to construct additional equipment they may not be able to access the funding required. This could further extend the time required for the necessary suite of equipment to be manufactured and deployed.

The current flowback language requires that this equipment must be available prior to stimulation even if it is known that the reservoir pressure/energy, pipeline pressure, and prior well behavior in an area preclude or make highly unlikely that a well can flow to sales. Requiring equipment on site even when it is known that REC's cannot be reasonably accomplished will unnecessarily exacerbate the equipment and personnel shortage problems with zero benefit while imposing unnecessary costs on the operators and ultimately the public. This unnecessary requirement will exacerbate the likely reduced well activity with the consequent job loss, lowering of gas supply, and raising of natural gas and electricity prices.

An additional potential economic harm is the requirements included in mineral leases. If the spud date of a well is delayed by very many months due to equipment availability, then there is a real risk that companies can find themselves in violation of leasing agreements that allow those agreements to be cancelled by the mineral owner. This "lease jeopardy" situation is a real danger in oil & gas operations and production companies take special pains to avoid it where possible. Requirements of REC will create a real risk that companies will lose leases that otherwise would have represented substantial value.

15.4.2. Availability of Experienced Operators

An additional significant concern with requiring implementation of the rule so quickly after the rule is finalized is that industry will have a shortage of experienced contractors or staff for complying with §60.5375(a) or doing "reduced emissions completions". Reduced emissions completions are very complicated and involve many safety issues/concerns with unique risks. The high pressure flow rates of fluids and sand can be quite dangerous. Inexperienced staff will not have adequate knowledge to properly manage the unique risks and prevent incidents from occurring. Industry will not have time to adequately train contractors or staff on how to safely do "reduced emissions completions" which again is likely to create unsafe conditions and operations.

U.S. Energy Information Administration

NATURAL GAS

OVERVIEW DATA ANALYSIS & PROJECTIONS GLOSSARY › FAQS ›

Number of Producing Gas Wells

≈ 490,000

Period: Annual

Area	2005	2006	2007	2008	2009	2010	View History
U.S.	425,887	440,516	452,945	476,652	493,100	487,627	1989-2010
Alabama	5,523	6,227	6,591	6,860	6,913	7,026	1989-2010
Alaska	227	231	239	261	261	269	1989-2010
Arizona	6	7	7	6	6	5	1989-2010
Arkansas	3,462	3,814	4,773	5,592	6,314	7,397	1989-2010
California	1,356	1,451	1,540	1,645	1,643	1,580	1989-2010
Colorado	22,691	20,568	22,949	25,716	27,021	28,813	1989-2010
Gulf of Mexico	2,123	2,419	2,552	1,527	1,984	1,852	1998-2010
Illinois	316	316	43	45	51	50	1989-2010
Indiana	2,321	2,336	2,350	525	563	620	1989-2010
Kansas	18,946	19,713	19,713	17,862	21,243	22,145	1989-2010
Kentucky	14,175	15,892	16,563	16,290	17,152	17,670	1989-2010
Louisiana	18,838	17,459	18,145	19,213	18,860	19,137	1989-2010
Maryland	7	7	7	7	7	7	1989-2010
Michigan	8,900	9,200	9,712	9,995	10,600	10,100	1989-2010
Mississippi	1,676	1,836	2,315	2,343	2,320	1,979	1989-2010
Missouri	0	0	0	0	0	0	1989-2010
Montana	5,751	6,578	6,925	7,095	7,031	6,059	1989-2010
Nebraska	114	114	186	322	285	276	1989-2010
Nevada	4	4	4	0	0	0	1996-2010
New Mexico	40,157	41,634	42,644	44,241	44,784	44,748	1989-2010
New York	5,449	5,985	6,680	6,675	6,628	6,736	1989-2010
North Dakota	148	200	200	194	196	188	1989-2010
Ohio	33,735	33,945	34,416	34,416	34,963	34,931	1989-2010
Oklahoma	36,704	38,060	38,364	41,921	43,600	44,000	1989-2010
Oregon	15	14	18	21	24	26	1989-2010
Pennsylvania	46,654	49,750	52,700	55,631	57,356	44,500	1989-2010
South Dakota	69	69	71	71	89	102	1989-2010
Tennessee	400	330	305	285	310	230	1989-2010
Texas	74,827	74,265	76,436	87,556	93,507	95,014	1989-2010
Utah	4,092	4,858	5,197	5,578	5,774	6,075	1989-2010
Virginia	4,132	5,179	5,735	6,426	7,303	7,470	1989-2010
West Virginia	49,335	53,003	48,215	49,364	50,602	52,498	1989-2010
Wyoming	23,734	25,052	27,350	28,969	25,710	26,124	1989-2010

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

Notes: Prior to 2001, the well counts for Federal Offshore Gulf of Mexico were included in the well counts for Alabama, Louisiana, and Texas. See Definitions, Sources, and Notes link above for more information on this table.

Release Date: 1/30/2012
Next Release Date: 2/29/2012

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Table 2-16 SBA Size Standards and Size Distribution of Oil and Natural Gas Firms

NAICS	NAICS Description	SBA Size Standard	Small Firms	Large Firms	Total Firms
Number of Firms by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	500	6,329	95	6,424
211112	Natural Gas Liquid Extraction	500	98	41	139
213111	Drilling Oil and Gas Wells	500	2,010	49	2,059
486210	Pipeline Transportation of Natural Gas	$7.0 million	61*	65*	126
Total Employment by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	500	55,622	77,664	133,286
211112	Natural Gas Liquid Extraction	500	1,875	6,648	8,523
213111	Drilling Oil and Gas Wells	500	36,652	69,774	106,426
486210	Pipeline Transportation of Natural Gas	$7.0 million	N/A*	N/A*	24,683
Estimated Receipts by Firm Size ($1000)					
211111	Crude Petroleum and Natural Gas Extraction	500	44,965,936	149,141,316	194,107,252
211112	Natural Gas Liquid Extraction	500	2,164,328	37,813,413	39,977,741
213111	Drilling Oil and Gas Wells	500	7,297,434	16,550,804	23,848,238
486210	Pipeline Transportation of Natural Gas	$7.0 million	N/A*	N/A*	20,796,681

Note: *The counts of small and large firms in NAICS 486210 is based upon firms with less than $7.5 million in receipts, rather than the $7 million required by the SBA Size Standard. We used this value because U.S. Census reports firm counts for firms with receipts less than $7.5 million. **Employment and receipts could not be split between small and large businesses because of non-disclosure requirements faced by the U.S. Census Bureau. Source: U.S. Census Bureau. 2010. "Number of Firms, Number of Establishments, Employment, Annual Payroll, and Estimated Receipts by Enterprise Receipt Size for the United States, All Industries: 2007." <http://www.census.gov/econ/susb/>

The small and large firms within NAICS 21311 are similarly distributed, with large firms accounting for about 2 percent of firms, but 66 percent and 69 percent of employment and estimated receipts, respectively. Because there are relatively few firms within NAICS 486210, the Census Bureau cannot release breakdowns of firms by size in sufficient detail to perform similar calculation.

Hydraulic Fracturing Q & A's

What is hydraulic fracturing?
Hydraulic fracturing is a proven technology that has been used since the 1940s in more than 1 million wells in the United States to help produce oil and natural gas. The technology involves pumping a water-sand mixture into underground rock layers where the oil or gas is trapped. The pressure of the water creates tiny fissures in the rock. The sand holds open the fissures, allowing the oil or gas to escape and flow up the well.

Is hydraulic fracturing widely used?
Yes, and its use is likely to increase. A government-industry study found that up to 80 percent of natural gas wells drilled in the next decade will require hydraulic fracturing. Hydraulic fracturing allows access to formations, like shale oil and shale gas, that had not been assessable before without the technology. It also allows more oil and natural gas to be brought to the surface from wells that had been produced without this technology.

Why is hydraulic fracturing important?
It enables production of more oil and natural gas, reducing dependence on foreign sources of energy and creating more jobs for Americans. It's an indispensable technology for producing much of our clean-burning natural gas, which heats more than 56 million American homes, generates one-fifth of our nation's electricity, powers buses and fleet vehicles and creates the basic materials for such things as fertilizers and plastics of every variety. When burned for energy, natural gas emits fewer greenhouse gases than other fossil fuels.

Doesn't hydraulic fracturing present a serious threat to the environment?
No. The environmental track record is good, and the technology is used under close regulatory supervision by state, local and federal regulators. Hydraulic fracturing has been used in nearly one million wells in the United States and studies by the U.S. EPA and the Ground Water Protection Council have confirmed no direct link between hydraulic fracturing operations and groundwater impacts.

How are the fluids kept away from aquifers and drinking water wells?
Wells are drilled away from drinking water wells. Also, fracturing usually occurs at depths well below where usable groundwater is likely to be found. Finally, when a well is drilled, steel casing and surrounding layers of concrete are installed to provide a safe barrier to protect usable water.

Who regulates hydraulic fracturing?
There are multiple federal, state and local government rules addressing environmental protection during oil and gas operations, including the protection of water resources. These rules cover well permitting, well materials and construction, safe disposition of used hydraulic fracturing fluids, water testing, and chemical recordkeeping and reporting. In addition, API has created a guidance document on proper well construction and plans to release guidance documents outlining best-available practices for water use and management and protecting the environment during hydraulic fracturing operations.

Isn't there a risk that hydraulic fracturing will use up an area's water supplies?
No. Local authorities control water use and can restrict it if necessary. In many areas, water is recycled and reused; in some cases companies pay for the water they use, which comes from a variety of sources. Water requirements for hydraulic fracturing are less than many other commercial and recreational uses. In Pennsylvania, for example, all the hydraulic fracturing activity taking place in 2009 used only 5 percent of the amount of water used for recreational purposes, like golf courses and ski slopes. State agencies manage water in a way that safeguards the water needs by nearby

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API hosts regional hydraulic fracturing workshops
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API Meetings

API Conference & Expo - March 6-8, 2012 - Singapore

U.S. Energy Information Administration

NATURAL GAS

OVERVIEW DATA ANALYSIS & PROJECTIONS GLOSSARY › FAQS ›

Natural Gas Annual Supply & Disposition by State
(Million Cubic Feet)

Data Series: Dry Production **Period:** Annual

Show Data By: Data Series / Area	2005	2006	2007	2008	2009	2010	View History
U.S.	18,050,598	18,503,605	19,266,026	20,158,602	20,623,854	21,332,420	1930-2010
Alabama	282,769	265,155	250,576	240,662	218,797	203,873	1982-2010
Alaska	459,326	420,086	407,153	374,105	374,152	353,391	1982-2010
Arizona	233	611	655	523	712	183	1982-2010
Arkansas	190,302	270,081	269,724	446,318	679,784	926,425	1982-2010
California	303,889	301,153	293,639	282,497	262,853	273,597	1982-2010
Colorado	1,098,304	1,166,504	1,204,391	1,335,809	1,431,463	1,495,742	1982-2010
Florida	2,121	2,055	1,646	2,414	257	12,409	1982-2010
Gulf of Mexico	3,132,089	2,901,969	2,798,718	2,314,342	2,428,916	2,245,062	1999-2010
Illinois	120	123	1,346	1,151	1,412	1,203	1982-2010
Indiana	3,135	2,921	3,606	4,701	4,927	6,802	1982-2010
Kansas	345,708	340,318	337,814	346,008	327,492	298,469	1982-2010
Kentucky	91,079	93,068	93,480	111,715	110,030	130,754	1982-2010
Louisiana	1,192,667	1,255,883	1,254,588	1,283,184	1,453,248	2,107,651	1982-2010
Maryland	46	48	35	28	43	43	1982-2010
Michigan	257,404	259,732	261,813	149,209	151,402	148,943	1982-2010
Mississippi	38,615	45,869	60,363	85,795	69,803	55,316	1982-2010
Missouri	0	0	0	0	0	0	1982-2010
Montana	106,769	111,423	115,272	110,907	96,392	86,172	1982-2010
Nebraska	1,172	1,200	1,555	3,082	2,908	2,231	1982-2010
Nevada	5	5	5	4	4	4	1991-2010
New Mexico	1,544,102	1,509,252	1,421,672	1,353,625	1,288,164	1,200,222	1982-2010
New York	55,180	55,980	54,942	50,320	44,849	35,813	1982-2010
North Dakota	45,699	48,019	52,817	44,566	49,229	70,456	1982-2010
Ohio	83,494	86,310	88,086	84,858	88,824	78,122	1982-2010
Oklahoma	1,551,906	1,597,048	1,687,039	1,782,021	1,788,665	1,706,697	1982-2010
Oregon	454	621	409	778	821	1,407	1982-2010
Pennsylvania	167,801	175,156	181,418	197,287	272,574	568,324	1982-2010
South Dakota	992	963	995	1,644	2,129	1,862	1982-2010
Tennessee	2,200	2,663	3,942	4,700	5,478	4,638	1982-2010
Texas	4,920,812	5,174,672	5,735,831	6,559,190	6,394,931	6,277,972	1982-2010
Utah	298,408	345,409	373,680	430,286	435,673	422,067	1982-2010
Virginia	88,610	103,027	112,057	128,454	140,738	147,255	1982-2010
West Virginia	213,433	217,513	223,113	236,489	255,650	256,567	1982-2010
Wyoming	1,571,754	1,748,766	1,973,648	2,191,928	2,241,532	2,212,748	1982-2010

- = No Data Reported; -- = Not Applicable; **NA** = Not Available; **W** = Withheld to avoid disclosure of individual company data.

Notes: Balancing Item volumes are equal to total disposition minus total supply. See Definitions, Sources, and Notes link above for more information on this table.

Release Date: 1/30/2012
Next Release Date: 2/29/2012

U.S. Energy Information Administration

PETROLEUM & OTHER LIQUIDS

OVERVIEW DATA ANALYSIS & PROJECTIONS GLOSSARY › FAQS ›

Crude Oil and Natural Gas Exploratory and Development Wells

Period: Annual

Data Series	2005	2006	2007	2008	2009	2010	View History
Wells Drilled (Number)							
Exploratory and Development	44,022	51,207	51,291	55,178	34,046	38,541	1949-2010
Crude Oil	10,779	13,260	13,385	16,792	11,485	16,708	1949-2010
Natural Gas	28,590	32,771	32,853	32,892	18,892	17,371	1949-2010
Dry Holes	4,653	5,176	5,053	5,494	3,669	4,462	1949-2010
Exploratory	4,142	4,640	5,219	5,129	2,975	3,018	1949-2010
Crude Oil	539	648	828	922	624	722	1949-2010
Natural Gas	2,141	2,455	2,796	2,445	1,266	1,156	1949-2010
Dry Holes	1,462	1,537	1,595	1,762	1,085	1,140	1949-2010
Development Wells Drilled	39,880	46,567	46,072	50,049	31,071	35,523	1949-2010
Crude Oil	10,240	12,612	12,557	15,870	10,861	15,986	1949-2010
Natural Gas	26,449	30,316	30,057	30,447	17,626	16,215	1949-2010
Dry Holes	3,191	3,639	3,458	3,732	2,584	3,322	1949-2010
Footage Drilled (Thousand Feet)							
Total	240,659	282,052	303,314	340,499	225,084	273,537	1949-2010

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

Notes: Geographic coverage is the 50 States and the District of Columbia. See Definitions, Sources, and Notes link above for more information on this table.

Release Date: 1/6/2012
Next Release Date: 2/2/2012

F.N. #15

IOP Publishing — Environmental Research Letters
Environ. Res. Lett. 6 (2011) 034014 (9pp) — doi:10.1088/1748-9326/6/3/034014

Life cycle greenhouse gas emissions of Marcellus shale gas

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Received 13 January 2011
Accepted for publication 14 July 2011
Published 5 August 2011
Online at stacks.iop.org/ERL/6/034014

Abstract
This study estimates the life cycle greenhouse gas (GHG) emissions from the production of Marcellus shale natural gas and compares its emissions with national average US natural gas emissions produced in the year 2008, prior to any significant Marcellus shale development. We estimate that the development and completion of a typical Marcellus shale well results in roughly 5500 t of carbon dioxide equivalent emissions or about 1.8 g CO_2e/MJ of gas produced, assuming conservative estimates of the production lifetime of a typical well. This represents an 11% increase in GHG emissions relative to average domestic gas (excluding combustion) and a 3% increase relative to the life cycle emissions when combustion is included. The life cycle GHG emissions of Marcellus shale natural gas are estimated to be 63–75 g CO_2e/MJ of gas produced with an average of 68 g CO_2e/MJ of gas produced. Marcellus shale natural gas GHG emissions are comparable to those of imported liquefied natural gas. Natural gas from the Marcellus shale has generally lower life cycle GHG emissions than coal for production of electricity in the absence of any effective carbon capture and storage processes, by 20–50% depending upon plant efficiencies and natural gas emissions variability. There is significant uncertainty in our Marcellus shale GHG emission estimates due to eventual production volumes and variability in flaring, construction and transportation.

Keywords: life cycle assessment, greenhouse gases, Marcellus shale, natural gas
[S] Online supplementary data available from stacks.iop.org/ERL/6/034014/mmedia

1. Introduction

Marcellus shale is a rapidly developing new source of US domestic natural gas. The Appalachian Basin Marcellus shale extends from southern New York through the western portion of Pennsylvania and into the eastern half of Ohio and northern West Virginia (Kargbo *et al* 2010). The estimated basin area is between 140 000 and 250 000 km^2 (Kargbo *et al* 2010), and has a depth ranging from 1200 to 2600 m (US DOE 2009). The shale seam's net thickness ranges from 15 to 60 m (US DOE 2009) and is generally thicker from west to east (Hill *et al* 2004). Figure 1 shows the location of the Marcellus and other shale gas formations in the continental United States.

Shale gas has become an important component of the current US natural gas production mix. In 2009, shale gas was 16% of the 21 trillion cubic feet (Tcf) or 600 million cubic meters (Mm^3) total dry gas produced (US EIA 2011a, 2011b). In 2035, the EIA expects the share to increase to 47% (12 Tcf or 340 Mm^3) of total gas production. The prospect of rapid shale gas development has resulted in interest in expanding

Table 1. Greenhouse gas estimation approaches and data sources.

Process	Estimation approaches	Data sources
Preparation of Well Pad:		
Vegetation clearing	Estimated area cleared multiplied by vegetative carbon storage to obtain carbon loss due to land use change	NY DEC (2009), Tilman *et al* (2006)
Well pad construction	Detailed cost estimate and EIO-LCA model	RSMeans (2005), CMU GDI (2010)
Well drilling:		
Drilling energy consumption	(1) Energy required and emission factor, and (2) cost estimate and EIO-LCA model	Harper (2008), Sheehan *et al* (2000), CMU GDI (2010)
Drilling mud production	(1) Cost estimate and EIO-LCA and (2) emission factors multiplied by quantity.	Shaker (2005), PRé Consultants (2007), CMU GDI (2010)
Drilling water consumption	Trucking emissions plus water treatment emissions multiplied by quantity	Wang and Santini (2009), URS Corporation (2010), PA DEP (2010), Stokes and Horvath (2006)
Hydraulic fracturing:		
Pumping	Pumping energy multiplied by emission factor	URS Corporation (2010), Kargbo *et al* (2010), Currie and Stelle (2010), Sheehan *et al* (2000)
Additives production	Additive quantities cost and EIO-LCA model	URS Corporation (2010), CMU GDI (2010)
Water consumption	Trucking emissions	Wang and Santini (2009), URS Corporation (2010), Stokes and Horvath (2006), PA DEP (2010)
Well completion:	If flaring, gas flow emission factor multiplied by flaring time	NY DEC (2009), PA DEP (2010)
Wastewater disposal:		
Deep well injection	Deep well injection costs and EIO-LCA model	US ACE (2006), CMU GDI (2010)
Production, processing, transmission and storage, and combustion	Assumed comparable to national average	Venkatesh *et al* (2011)

ranges of process parameters. Table 1 summarizes estimation approaches used in this study, while calculation details appear in the supplementary information (available at stacks.iop.org/ERL/6/034014/mmedia).

In section 3.1, we report point estimates of GHG emissions for a base case. In section 5, we report range estimates and consider the sensitivity of point estimates to particular assumptions. Table 2 summarizes important parameter assumptions and possible ranges. Uniform or triangular distributions are assigned to these parameters based on whether we had two (uniform) or three (triangular) data points. When more data was available, parameters of probability distributions that best fit the data were estimated. A Monte Carlo analysis was performed using these distributions, to estimate the emissions from the various activities considered in our life cycle model.

3.1. Emissions from Marcellus shale gas preproduction

Horizontal wells are drilled on a multi-well pad to achieve higher cost-effectiveness. It is reported that a Marcellus well pad might have as few as one well per pad and as many as 16, but more typically 6–8 (ICF International 2009, NY DEC 2009, Currie and Stelle 2010). As a base case scenario, we chose to analyze the typical pad with six wells, each producing 2.7 Bcf (3.0×10^9 MJ), representing an average of 0.3 MMcf per day of gas for 25 years. Other production estimates are higher. EQT (2011), for example, provides a production estimate of 7.3 Bcf (8.1×10^9 MJ) and Range Resources at 4.4 Bcf (4.9×10^9 MJ) (Ventura 2009). Within the LCA framework the impacts are distributed across the total volume of gas produced during the lifetime of the well. Thus, the choice of using the low end ultimate recovery as the base case should be considered conservative. With Marcellus shale gas production currently in its infancy, the average production characteristics have significant uncertainty, so we perform an

Table 2. Parameter assumptions and ranges. (Note: sources for base case and range values are in table 1 and discussed in the supplementary material (available at stacks.iop.org/ERL/6/034014/mmedia).)

Parameter	Base case	Range
Area of access road (acres)	1.43	0.1–2.75
Wells per pad (number)	6	1–16
Area of well pad (acres)	5	2–6
Vertical drilling depth (ft)	8500	7000–10 000
Horizontal drilling length (ft)	4000	2000–6000
Fracturing water (MMgal/well)	4	2–6
Flowback fraction (%)	37.5	35–40
Recycling fraction (%)	45	30–60
Trucking distance between well site and water source (miles)	5	0–10
Trucking distance between well site and deep well injection facility (miles)	80	3–280
Well completion time with collection system in place (h)	18	12–24
Well completion time without collection system in place (days)	9.5	4–15
Fraction of flaring (%)	76	51–100
Initial 30 day gas flow rate (MMscf/day)	4.1	0.7–10
Average well production rate (MMscf/day)	0.3	0.3–10
Well lifetime (years)	25	5–25

Figure 4: AAPG Basins Represented in Survey Sample (Non-GC Only)

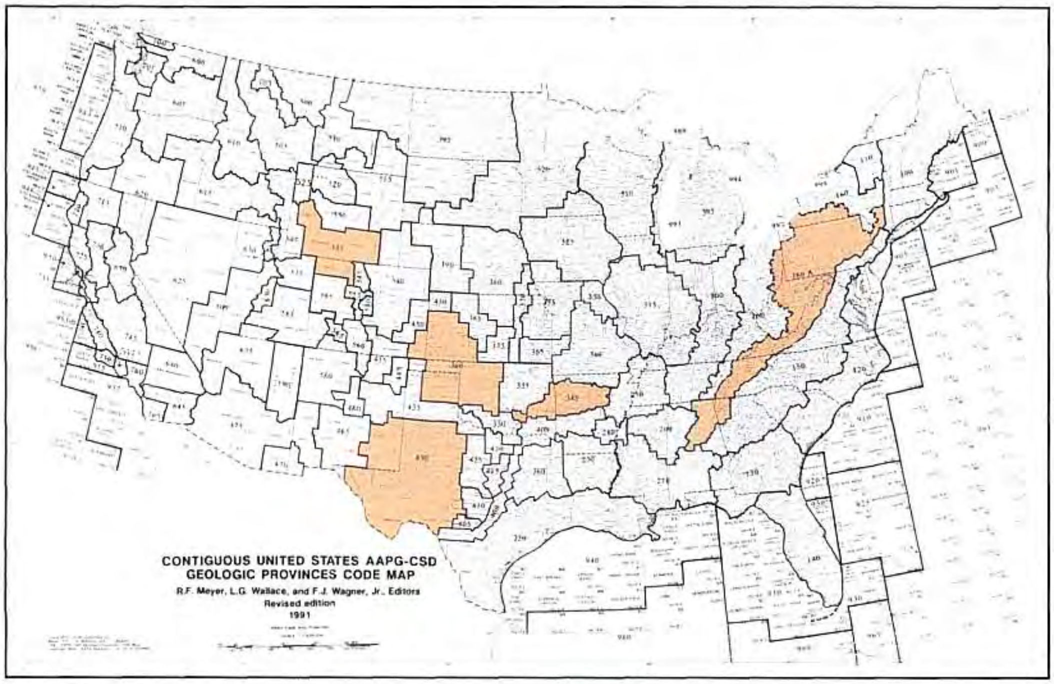
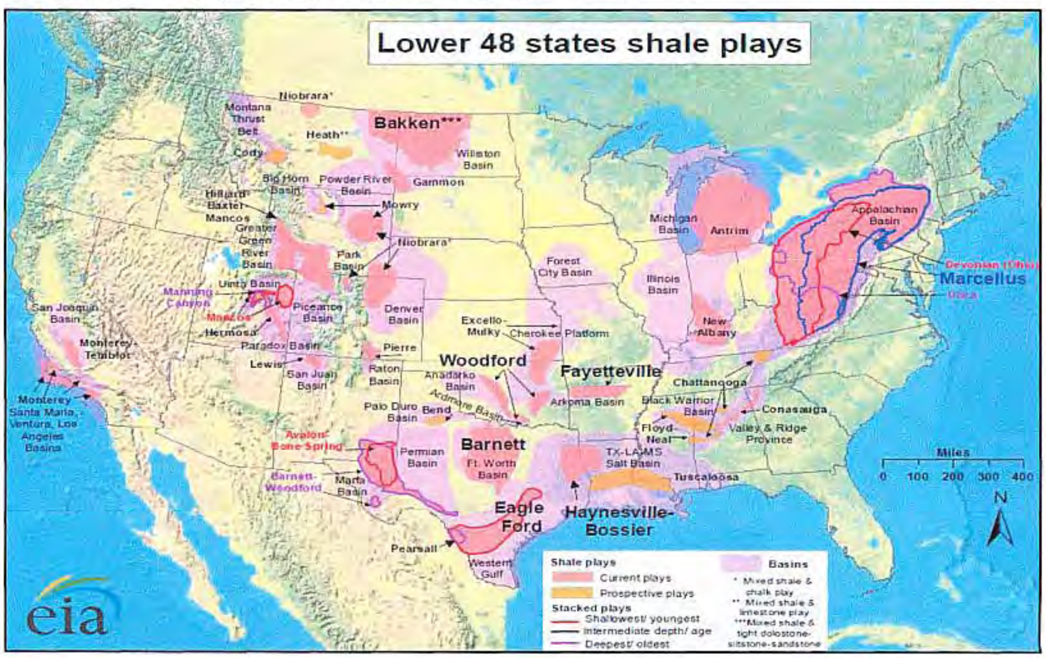


Figure 5: Location of Major Shale Plays in Continental US



Source:
http://www.slb.com/services/industry_challenges/~/media/Files/industry_challenges/unconventional_gas/other/shale_plays_lower_48.ashx

U.S. Energy Information Administration

Home › Forecasts & Analysis › 4. Mid-Term Trends in Natural Gas Supply and Prices › Recent Efficiency Improvements in the Natural Gas Production Industry

U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply

Report #: SR-OIAF/2001-06
Released Date: December 2001
Next Release Date: One-Time

Recent Efficiency Improvements in the Natural Gas Production Industry

Efficiency improvements in the natural gas production industry since the introduction of wellhead price deregulation and open-access transportation can be gauged by examining a number of secondary measures. Indirect measures must be used, because per-unit production costs cannot be measured directly for a number of reasons, including:

- Co-production of natural gas, natural gas liquids, and oil from the same wells
- Reporting of natural gas reserves additions and natural gas well drilling activities at different points in time
- Inability to apportion "dry well" drilling costs precisely to oil and natural gas production
- Reporting of wells that produce both oil and natural gas as "oil wells"
- Lack of reporting on lease payments and geophysical expenses or, when they are reported, inability to apportion them to oil and natural gas.

Two secondary measures of natural gas production industry efficiency can be evaluated from 1985 through the present, a period when the industry has operated in a fully competitive market environment.

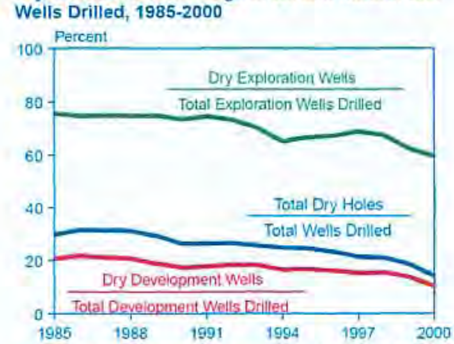
The initial flow rate of new natural gas well completions is an indicator of how well natural gas producers are doing in replacing depleted wells. As shown in the following figure, lower 48 gas wells have demonstrated higher initial rates of production, going from 1,341 thousand cubic feet per day per completion in 1985 to 1,712 thousand cubic feet per day per completion in 2000. Because initial production rates vary from year to year, a comparison of 5-year averages best illustrates the trend. From 1986 through 1990, the initial gas well completion averaged 1,451 thousand cubic feet per day per completion; from 1996 through 2000, the average initial completion rate was 1,900 thousand cubic feet per day per completion, an increase of 31 percent. Much of the improvement can be attributed to Texas, where the average initial flow rate increased from 975 thousand cubic feet per day per completion in 1985 to 1,732 thousand cubic feet per day per completion in 2000, a 78-percent increase. In comparison, the increases in other regions were less impressive: 3.8 percent for the Gulf of Mexico, 11.9 percent for Oklahoma, and 10.4 percent for the Rocky Mountain region.

Perhaps one of the least ambiguous measures of increased drilling efficiency is the percentage of dry holes drilled by the oil and natural gas industry in the pursuit of new oil and natural gas reserves. (Because dry holes cannot be strictly attributed to either the oil or natural gas side of the industry, the percentage of dry holes drilled in the search for natural gas cannot be determined.) Irrespective of the type of well drilled, dry holes have declined as a percentage of the total oil and natural gas wells drilled, as shown in the figure below.

Initial Flow Rates of New Natural Gas Well Completions, 1985-2000

Source: Energy Information Administration, Office of Oil and Gas, Reserves and Production Division.

Dry Holes as a Percentage of Oil and Natural Gas Wells Drilled, 1985-2000



Source: Energy Information Administration, Office of Oil and Gas, Reserves and Production Division.

Hydraulic Fracturing Considerations for Natural Gas Wells of the Fayetteville Shale

Authors: J. Daniel Arthur, P.E., ALL Consulting; Brian Bohm, P.G., ALL Consulting; Bobbi Jo Coughlin, EIT, ALL Consulting; Mark Layne, Ph.D., P.E., ALL Consulting

Lead Author Biographical Sketch

Dan Arthur is a founding member and the Managing Partner of ALL Consulting (www.all-llc.com). Mr. Arthur earned his bachelors degree in Petroleum Engineering from the University of Missouri-Rolla. He is a recognized authority on environmental issues pertaining to unconventional resource development and production. Mr. Arthur has served or is currently serving as the lead researcher on several significant projects involving unconventional resources; environmental considerations pertaining to shale gas development; produced water management and recycling; access to federal lands; and low impact natural gas and oil development. Has previously managed U.S. Department of Energy (DOE) funded research projects involving the development of best management practices utilizing GIS technologies for efficient environmental protection during unconventional resource Development and Production; research to develop a national primer on coal bed methane; research to develop a Handbook on the preparation and review of environmental documents for CBM development; and research with the Ground Water Protection Research Foundation (GWPRF) and funded by DOE and BLM involving analysis of produced water management alternatives and beneficial uses of coal bed methane produced water. Mr. Arthur has published many articles and reports and has made numerous presentations on environmental, energy, and technology issues.

Abstract

Hydraulic fracturing is a key component of the successful development model for shale gas plays. This paper will review the evolution of hydraulic fracturing, including environmental and regulatory considerations related to development of the Fayetteville Shale play. Technical and environmental considerations are presented applicable to hydraulic fracturing in the unconventional arena of gas shales with an emphasis on the Fayetteville Shale of the Arkoma Basin. Topics addressed in the paper will include discussion on why hydraulic fracturing is performed; the hydraulic fracturing process; applicable design and engineering aspects of well completions; geological considerations such as confinement of the fracturing process; potential risks to groundwater and underground sources of drinking water; and the composition of hydraulic fracturing fluids and associated technical considerations.

Exhibit 3 is a summary of the characteristics for select U.S. gas shale plays and provides several characteristics for comparison including; estimated reserves, play size, production volumes, depth to production zone, characteristics of the shales and estimated or known well spacing. Exhibit 3 shows the variations in depth of target formation across the different plays with Haynesville Shale development representing some of the deepest at more than 10,000 feet below land surface (ft bls). Exhibit 3 also highlights those formations with largest estimated maximum recoverable gas volumes (Haynesville and Marcellus Shales) having six to eight times greater volumes than the Barnett Shale.

Exhibit 3. Comparison of Data for the Active Gas Shales in the United States

Gas Shale Basin	Fayetteville	Barnett	Marcellus	Haynesville	Woodford	Lewis
Estimated Basin Area, square miles	9,000	5,000	95,000	9,000	11,000	10,000
Depth, ft	1,000-7,000[12]	6, 500 - 8,500[12]	4,000-8,500[13]	10,500-13,500[13]	6,000-11,000[3]	3,000-6000[12]
Net Thickness, ft	20-200[12]	100-600[12]	50-200[6]	200-300[714]	120-220[12]	200-300[12]
Depth to Base of Treatable Water, ft#	~500[15]	~1200	~850	~400	~400	~2000
Total Organic Carbon, %	4.0-9.8[12]	4.5[12]	3-12	0.5 – 4.0[14]	1-14	0.45-2.5[12]
Total Porosity, %	2-8[12]	4-5[12]	10	8-9	3-9	3.0-5.5[12]
Gas Content, scf/ton	60-220[12]	300-350[12]	60-100	100-330	200-300	15-45[12]
Water Production, Barrels water/day[12]	0	0	0	0		0
Well spacing, Acres	40-160	40-160[6]	40-160[6]	40-560[6]	640[6]	80-320[12]
Gas-In-Place, Tcf	52[3]	1,500[3]	1,500[3]	717[3]	52[3]	61.4[3]
Reserves, Tcf	41.6[3]	262[3], 500	262[3], 500	251[3]	11.4[3]	20[3]
Est. Gas Production, mcf/day/well	530	3,100	3,100	625-1800[13]	415	100-200[12]

mcf = thousands of cubic feet of gas.

NOTE: Data derived from various sources and research analysis. Information from some basins was unable to be identified and confirmed at the time of this paper and has been left blank.

- for the Depth to base of treatable water data, the data was based on depth of casing information if the state's oil and gas agency did not specifically report BTW values in their data base.

Estimated depth to target zone data and base of treatable water data demonstrates that most gas shale development is projected to occur thousands of feet below treatable water zones. In analyzing Fayetteville data, it is important to understand that the Arkansas Oil and Gas Commission (AOGC) regulates the depth of protective casings (as do other state oil & gas regulatory agencies) based on field rules in order to protect groundwater resources[15]. These rules and regulations are not exclusive to Arkansas. Oil and Gas agency rules regarding depth of casings in order to protect groundwater resources are common to state oil and gas programs throughout the United States.

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Exhibit 1 – Susan Harvey CV

HARVEY CONSULTING, LLC.

Oil & Gas, Environmental, Regulatory Compliance, and Training

Susan L. Harvey, Owner

Susan Harvey has 25 years of experience as a Petroleum and Environmental Engineer, working on oil and gas exploration and development projects. Ms. Harvey is the owner of Harvey Consulting, LLC, a consulting firm providing oil and gas, environmental, regulatory compliance advice and training to clients. Ms. Harvey held engineering and supervisory positions at both Arco and BP including Prudhoe Bay Engineering Manager and Exploration Manager. Ms. Harvey has planned, engineered, executed and managed both on and offshore exploration and production operations, and has been involved in the drilling, completion, stimulation, testing and oversight of hundreds of wells in her career. Ms. Harvey's experience also includes air and water pollution abatement design and execution, best management practices, environmental assessment of oil and gas project impacts, and oil spill prevention and response planning. During Governor Knowles Administration, Ms. Harvey headed the Industry Preparedness Program for the Alaska Department of Environmental Conservation, Division of Spill Prevention and Response; she was responsible for oil spill prevention and response oversight of all Alaska industry operations that produce, store or transport hydrocarbons. Ms. Harvey taught air pollution control engineering courses at the University of Alaska in the Graduate Engineering Program.

Education Summary:

Environmental Engineering
Masters of Science
University of Alaska Anchorage

Petroleum Engineering
Bachelor of Science
University of Alaska Fairbanks

Consulting Services:

- Oil and gas, environmental, regulatory compliance advice and training
- Oil spill prevention and response planning
- Air pollution assessment and control

Employment Summary:

2002-Current	Harvey Consulting, LLC., Owner
2005-Current	Harvey Fishing, LLC., Co-owner
2002-2007	University of Alaska at Anchorage Environmental Engineering Graduate Level, Adjunct Professor
1999-2002	State of Alaska, Department of Environmental Conservation Environmental Supervisory Position
1996-1999	Arco Alaska Inc. Engineering and Supervisory Positions held
1989-1996	BP Exploration (Alaska), Inc. Environmental, Engineering, and Supervisory Positions held
1987-1989	Standard Oil Production Company *(purchased by BP in 1989),* Engineering Position
1985-1986	Conoco, Production Engineer and New Mexico Institute of Mining and Technology Petroleum Research & Recovery Center, Laboratory Research Assistant

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Harvey Consulting, LLC
PO Box 771026 Eagle River, Alaska 99577
Email:sharvey@mtaonline.net; Phone: (907) 694-7994; Fax: (907) 694-7995

Employment Detail:

2002-Current **Harvey Consulting, LLC.**
Owner of consulting business providing oil and gas, environmental, regulatory compliance and training to clients.

2005-Current **Harvey Fishing, LLC.**
Co-owner and operator of a commercial salmon fishing business in Prince William Sound Alaska.

2002-2007 **University of Alaska at Anchorage**
Environmental Engineering Graduate Level Program, Adjunct Professor Air Pollution Control.

1999-2002 **State of Alaska, Department of Environmental Conservation**
Environmental Supervisory Position
Industry Preparedness and Pipeline Program Manager, Alaska Department of Environmental Conservation, Division of Spill Prevention and Response. Managed 30 staff in four remote offices. Main responsibility was to ensure all regulated facilities and vessels across Alaska submitted high quality Oil Discharge Prevention and Contingency Plans to prevent and respond to oil spills. Staff included field and drill inspectors, engineers, and scientists. Managed all required compliance and enforcement actions.

1996-1999 **Arco Alaska Inc.**
Engineering and Supervisory Positions held
Prudhoe Bay Waterflood and Enhanced Oil Recovery Engineering Supervisor. Main responsibility was to set the direction for a team of engineers to design, optimize and manage the production over 120,000 barrels of oil per day from approximately 400 wells and nine drill sites, from the largest oil field in North America. Responsible for six concurrently operating drilling and workover rigs.

Prudhoe Bay Satellite Exploration Engineering Supervisor for development of six new Satellites Oil Fields. Main responsibility was to set the direction for a multidisciplinary team of Engineers, Environmental Scientists, Facility Engineers, Business Analysts, Geoscientists, Land, Tax, Legal, and Accounting. Responsible for two appraisal drilling rigs.

Lead Engineer for Arco Western Operating Area Development Coordination Team. Lead a multi-disciplinary team of engineers and geoscientists, working on the Prudhoe Bay oil field.

1989-1996 **BP Exploration (Alaska), Inc.**
Environmental, Engineering, and Supervisory Positions held
Senior Engineer Environmental & Regulatory Affairs Department. Main responsibilities included: air quality engineering, technical and permitting support for Northstar, Badami, Milne Point Facilities and Exploration Projects.

Senior Engineer/Litigation Support Manager. Duties included managing a multidisciplinary litigation staff to support the ANS Gas Royalty Litigation, Quality Bank Litigation and Tax Litigation. Main function was to coordinate, plan and organize the flow of work amongst five contract attorneys, seven in-house attorneys, two technical consultants, eight expert witnesses, four in-house consultants and twenty-two staff members.

Senior Planning Engineer. Provided technical, economic, and negotiations support on Facility, Power, Water and Communication Sharing Agreements. Responsibilities also included providing technical assistance on recycled oil issues, ballast water disposal issues, chemical treatment options, and contamination issues.

Production Planning Engineer. Coordinated State approval of the Sag Delta North Participating Area and Oil Field. Resolved technical, legal, tax, owner and facility sharing issues. Developed an LPG feasibility study for the Endicott facility.

Reservoir Engineer. Developed, analyzed and recommended options to maximize recoverable oil reserves for the Endicott Oil Field through 3D subsurface reservoir models, which predicted fluid movements and optimal well placement for the drilling program. Other duties included on-site wellbore fluid sampling and subsequent lab analysis.

Production Engineer. North Slope field engineering. Duties included design and implementation of wireline, electric line, drilling and rig completions, well stimulation, workovers and well testing programs.

1987-1989 **Standard Oil Production Company, Production Engineer**

Production Engineer. North Slope field engineering. Duties included design and implementation of wireline, electric line, drilling and rig completions, well stimulation, workovers and well testing programs.

Engineering Internship, Barry Waterflood Oklahoma City OK.

1986 **Conoco, Production Engineer**

Production Engineer. Engineering Internship, Hobbs New Mexico.

1985-1986 **New Mexico Institute of Mining and Technology**
Petroleum Research & Recovery Center

Laboratory Research Assistant, Enhanced Oil Recovery, Surfactant Research.

Harvey Consulting, LLC, Major Projects and Publications

Northeast Natural Energy, LLC. and Enrout Properties, LLC vs. The City of Morgantown, West Virginia, technical support to The City of Morgantown, 2011.

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Shell Beaufort Sea Exploration Plan, technical support to North Slope Borough, 2007-2011.

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Gas Well Risk Management Controls, Protection of Groundwater Resources and Safe Well Construction, Operation and Abandonment, analysis prepared for Environmental Defense Fund and Sierra Club, 2010.

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Oil & Gas Exploration and Production Operations Inspector Training and Manual, prepared for North Slope Borough, 2010.

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Alpine Oil Development Oil Discharge Prevention and Contingency plan, technical review completed for support for the North Slope Borough, 2008.

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Exhibit 2

Hydrocarbon Emissions Characterization in the Colorado Front Range – A Pilot Study

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Abstract

The multi-species analysis of daily air samples collected at the NOAA Boulder Atmospheric Observatory (BAO) in Weld County in northeastern Colorado since 2007 shows highly correlated alkane enhancements caused by a regionally distributed mix of sources in the Denver-Julesburg Basin. To further characterize the emissions of methane and non-methane hydrocarbons (propane, n-butane, i-pentane, n-pentane and benzene) around BAO, a pilot study involving automobile-based surveys was carried out during the summer of 2008. A mix of venting emissions (leaks) of raw natural gas and flashing emissions from condensate storage tanks can explain the alkane ratios we observe in air masses impacted by oil and gas operations in northeastern Colorado. Using the WRAP Phase III inventory of total volatile organic compound (VOC) emissions from oil and gas exploration, production and processing, together with flashing and venting emission speciation profiles provided by State agencies or the oil and gas industry, we derive a range of bottom-up speciated emissions for Weld County in 2008. We use the observed ambient molar ratios and flashing and venting emissions data to calculate top-down scenarios for the amount of natural gas leaked to the atmosphere and the associated methane and non-methane emissions. Our analysis suggests that the emissions of the species we measured are most likely underestimated in current inventories and that the uncertainties attached to these estimates can be as high as a factor of two.

1) Introduction

Since 2004, the National Oceanic and Atmospheric Administration Earth System Research Laboratory (NOAA ESRL) has increased its measurement network density over North America, with continuous carbon dioxide (CO_2) and carbon monoxide (CO) measurements and daily collection of discrete air samples at a network of tall towers [Andrews et al., in preparation] and bi-weekly discrete air sampling along vertical aircraft profiles [Sweeney et al., in preparation]. Close to 60 chemical species or isotopes are measured in the discrete air samples, including long-lived greenhouse gases (GHGs) such as CO_2, methane (CH_4), nitrous oxide (N_2O), and sulfur hexafluoride (SF_6), tropospheric ozone precursors such as CO and several volatile organic compounds (VOCs), and stratospheric-ozone-depleting substances. The NOAA multi-species regional data set provides unique information on how important atmospheric trace gases vary in space and time over the continent, and it can be used to quantify how different processes contribute to GHG burdens and/or affect regional air quality.

In this study we focus our analysis on a very strong alkane atmospheric signature observed downwind of the Denver-Julesburg Fossil Fuel Basin (DJB) in the Colorado Northern Front Range (Figures 1 and 1S). In 2008, the DJB was home to over 20,000 active natural gas and condensate wells. Over 90% of the production in 2008 came from tight gas formations.

A few recent studies have looked at the impact of oil and gas operations on air composition at the local and regional scales in North America. Katzenstein et al. [2003] reported results of two intensive surface air discrete sampling efforts over the Anadarko

Fossil Fuel Basin in the southwestern United States in 2002. Their analysis revealed substantial regional atmospheric CH_4 and non-methane hydrocarbon (NMHC) pollution over parts of Texas, Oklahoma, and Kansas, which they attributed to emissions from the oil and gas industry operations. More recently, Schnell et al. [2009] observed very high wintertime ozone levels in the vicinity of the Jonah-Pinedale Anticline natural gas field in western Wyoming. Ryerson et al. [2003], Wert et al. [2003], de Gouw et al. [2009] and Mellqvist et al. [2009] reported elevated emissions of alkenes from petrochemical plants and refineries in the Houston area and studied their contribution to ozone formation. Simpson et al. [2010] present an extensive analysis of atmospheric mixing ratios for a long list of trace gases over oil sands mining operations in Alberta during one flight of the 2008 Arctic Research of the Composition of the Troposphere from Aircraft and Satellites campaign. Our study distinguishes itself from previous ones by the fact that it relies substantially on the analysis of daily air samples collected at a single tall-tower monitoring site between August 2007 and April 2010.

Colorado has a long history of fossil fuel extraction [Scamehorn, 2002]. Colorado natural gas production has been increasing since the 1980s, and its share of national production jumped from 3% in 2000 to 5.4% in 2008. 1.3% of the nationally produced oil in 2008 also came from Colorado, primarily from the DJB in northeastern Colorado and from the Piceance Basin in western Colorado. As of 2004, Colorado also contained 43 natural gas processing plants, representing 3.5% of the conterminous US processing capacity [EIA, 2006], and two oil refineries, located in Commerce City, in Adams County just north of Denver.

Emissions management requirements for both air quality and climate-relevant gases have led the state of Colorado to build detailed baseline emissions inventories for ozone precursors, including volatile organic compounds (VOCs), and for GHGs. Since 2004, a large fraction of the Colorado Northern Front Range, including Weld County and the Denver metropolitan area, has been in violation of the 8-hour ozone national ambient air quality standard [CDPHE, 2008a]. In December 2007, the Denver and Colorado Northern Front Range (DNFR) region was officially designated as a Federal Non-Attainment Area (NAA) for repeated violation in the summertime of the ozone National Ambient Air Quality Standard (see area encompassed by golden boundary in Figure 1). At the end of 2007, Colorado also adopted a Climate Action Plan, which sets greenhouse gas emissions reduction targets for the state [Ritter, 2007].

Methane, a strong greenhouse gas with a global warming potential (GWP) of 25 over a 100 yr time horizon [IPCC, 2007], accounts for a significant fraction of Colorado GHG emissions, estimated at 14% in 2005 ([Strait et al., 2007] and Table 1S; note that in this report, the oil and gas industry CH_4 emission estimates were calculated with the EPA State Greenhouse Gas Inventory Tool). The natural gas industry (including exploration, production, processing, transmission and distribution) is the single largest source of CH_4 in the state of Colorado (estimated at 238 Gg/yr or ktonnes/yr), followed closely by coal mining (233 Gg/yr); note that all operating surface and underground coal mines are now in western Colorado. Emission estimates for oil production operations in the state were much lower, at 9.5 Gg/yr, than those from gas production. In 2005, Weld County represented 16.5% of the state's natural gas production and 51% of the state crude oil/ natural gas condensate production (Table 2S). Scaling the state's total CH_4 emission estimates from Strait et al. [2007], rough estimates for the 2005 CH_4 source from natural gas production and processing operations and from natural gas condensate/oil production in Weld County are 19.6 Gg and 4.8 Gg, respectively. It is important to stress here that there are large uncertainties associated with these inventory-derived estimates.

Other important sources of CH_4 in the state include large open-air cattle feedlots, landfills, wastewater treatment facilities, forest fires, and agriculture waste burning, which are all difficult to quantify. 2005 state total CH_4 emissions from enteric fermentation and manure management were estimated at 143 and 48 Gg/yr, respectively [Strait et al., 2007]; this combined source is of comparable magnitude to the estimate from natural gas systems. On-road transportation is not a substantial source of methane [Nam et al., 2004].

In 2006, forty percent of the DNFR NAA's total anthropogenic VOC emissions were estimated to be due to oil and gas operations [CDPHE, 2008b]. Over the past few years, the State of Colorado has adopted more stringent VOC emission controls for oil and gas exploration and processing activities. In 2007, the Independent Petroleum Association of Mountain States (IPAMS, now Western Energy Alliance), in conjunction with the Western Regional Air Partnership (WRAP), funded a working group to build a state-of-the-knowledge process-based inventory of total VOC and NOx sources involved in oil and gas exploration, production and gathering activities for the western United State's fossil fuel basins, hereafter referred to as the WRAP Phase III effort (http://www.wrapair.org/forums/ogwg/index.html). Most of the oil and gas production in the DJB is concentrated in Weld County. Large and small condensate storage tanks in the County are estimated to be the largest VOC fossil fuel production source category (59%

and 9% respectively), followed by pneumatic devices (valve controllers) and unpermitted fugitives emissions (13% and 9% respectively). A detailed breakdown of the WRAP oil and gas source contributions is shown in Figure 2S for 2006 emissions and projected 2010 emissions [Bar-Ilan et al., 2008a,b]). The EPA NEI 2005 for Weld County, used until recently by most air quality modelers, did not include VOC sources from oil and natural gas operations (Table 3S).

Benzene (C_6H_6) is a known human carcinogen and it is one of the 188 hazardous air pollutants (HAPs) tracked by the EPA National Air Toxics Assessment (NATA). Benzene, like VOCs and CH_4, can be released at many different stages of oil and gas production and processing. Natural gas itself can contain varying amounts of aromatic hydrocarbons, including C_6H_6 [EPA, 1998]. Natural gas associated with oil production (such sources are located in several places around the DJB) usually has higher C_6H_6 levels [Burns et al., 1999] than non-associated natural gas. Glycol dehydrators used at wells and processing facilities to remove water from pumped natural gas can vent large amounts of C_6H_6 to the atmosphere when the glycol undergoes regeneration [EPA, 1998]. Condensate tanks, venting and flaring at the well-heads, compressors, processing plants, and engine exhaust are also known sources of C_6H_6 [EPA, 1998]. C_6H_6 can also be present in the liquids used for fracturing wells [EPA, 2004].

In this paper, we focus on describing and interpreting the measured variability in CH_4 and C_{3-5} alkanes observed in the Colorado Northern Front Range. We use data from daily air samples collected at a NOAA tall tower located in Weld County as well as continuous CH_4 observations and discrete targeted samples from an intensive mobile sampling campaign in the Colorado Northern Front Range. These atmospheric measurements are then used together with other emissions data sets to provide an independent view of methane and non-methane hydrocarbon emissions inventory results.

The paper is organized as follows. Section 2 describes the study design and sampling methods. Section 3 presents results from the tall tower and the Mobile Lab surveys, in particular the strong correlation among the various alkanes measured. Based on the multi-species analysis in the discrete air samples, we were able to identify two major sources of C_6H_6 in Weld County. In section 4.1 we discuss the results and in section 4.2 we compare the observed ambient molar ratios with other relevant data sets, including raw natural gas composition data from 77 gas wells in the DJB. The last discussion section, 4.3, is an attempt to shed new light on methane and VOC emission estimates from oil and gas operations in Weld County. We first describe how we derived speciated bottom-up emission estimates based on the WRAP Phase III total VOC emission inventories for counties in the DJB. We then used 1) an average ambient propane-to-methane molar ratio, 2) a set of bottom-up estimates of propane and methane flashing emissions in Weld County and 3) three different estimates of the propane-to-methane molar ratio for the raw gas leaks to build top-down methane and propane emission scenarios for venting sources in the county. We also scaled the top-down propane (C_3H_8) estimates with the observed ambient alkane ratios to calculate top-down emission estimates for n-butane (n-C_4H_{10}), i- and n-pentane (i-C_5H_{12}, n-C_5H_{12}), and benzene. We summarize our main conclusions in section 5.

2) The Front Range Emissions Study: Sampling Strategy, Instrumentation, and Sample Analysis

2.1. Overall Experimental Design

The Colorado Northern Front Range study was a pilot project to design and test a new measurement strategy to characterize GHG emissions at the regional level. The anchor of the study was a 300-m tall tower located in Weld County, 25 km east-northeast of Boulder and 35 km north of Denver, called the Boulder Atmospheric Observatory (BAO) [40.05^{o}N, 105.01^{o}W; base of tower at 1584 m above sea level] (Figure 1). The BAO is situated on the southwestern edge of the DJB. A large landfill and a wastewater treatment plant are located a few kilometers southwest of BAO. Interstate 25, a major highway going through Denver, runs in a north-south direction 2 km east of the site. Both continuous and discrete air sampling have been conducted at BAO since 2007.

To put the BAO air samples into a larger regional context and to better understand the sources that impacted the discrete air samples, we made automobile-based on-road air sampling surveys around the Colorado Northern Front Range in June and July 2008 with an instrumented "Mobile Lab" and the same discrete sampling apparatus used at all the NOAA towers and aircraft sampling sites.

2.2. BAO and other NOAA cooperative Tall Towers

The BAO tall tower has been used as a research facility of boundary layer dynamics since the 1970s [Kaimal and Gaynor, 1983]. The BAO tower was instrumented by the NOAA ESRL Global Monitoring Division (GMD) in Boulder in April 2007, with sampling by a quasi-continuous CO_2 non-dispersive infrared sensor and a CO Gas Filter Correlation instrument, both oscillating between three intake levels (22, 100 and 300 m above ground level) [Andrews et al., in preparation]. Two continuous ozone UV-absorption instruments have also been deployed to monitor ozone at the surface and at the 300-m level.

The tower is equipped to collect discrete air samples from the 300-m level using a programmable compressor package (PCP) and a programmable flasks package (PFP) described later in section 2.4. Since August 2007 one or two air samples have been taken approximately daily in glass flasks using PFPs and a PCP. The air samples are brought back to GMD for analysis on three different systems to measure a series of compounds, including methane (CH_4 , also referred to as C_1), CO, propane (C_3H_8, also referred to as C_3), n-butane (n-C_4H_{10}, nC_4), isopentane (i-C_5H_{12}, iC_5), n-pentane (n-C_5H_{12}, nC_5), acetylene (C_2H_2), benzene, chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs) and hydrofluorocarbons (HFCs). Ethane and i-butane were not measured.

In this study, we use the results from the NOAA GMD multi-species analysis of air samples collected midday at the 300-m level together with 30- second wind speed and direction measured at 300-m. 30-minute averages of the wind speed and direction prior to the collection time of each flask are used to separate samples of air masses coming from three different geographic sectors: the North and East (NE sector), where the majority of the DJB oil and gas wells are located; the South (S sector), mostly influenced by the Denver metropolitan area; and the West (W sector), with relatively cleaner air.

In 2008, NOAA and its collaborators were operating a regional air sampling network of eight towers and 18 aircraft profiling sites located across the continental US employing in-situ measurements (most towers) and flask sampling protocols (towers and aircraft sites) that were similar to those used at BAO. Median mixing ratios for several alkanes, benzene, acetylene, and carbon monoxide from BAO and a subset of five other

NOAA towers and from one aircraft site are presented in the Results (Section 3). Table 1 provides the three letter codes used for each sampling site, their locations and sampling heights. STR is located in San Francisco. WGC is located 34 km south of downtown Sacramento in California's Central Valley where agriculture is the main economic sector. Irrigated crop fields and feedlots contribute to the higher CH_4 observed at WGC. The LEF tower in northern Wisconsin is in the middle of the Chequamegon National Forest which is a mix of temperate/boreal forest and lowlands/wetlands [Werner et al., 2003]. Air samples from NWF (surface elevation 3050m), in the Colorado Rocky Mountains, mostly reflect relatively unpolluted air from the free troposphere. The 457m tall Texas tower (WKT) is located between Dallas/Fort Worth and Austin. It often samples air masses from the surrounding metropolitan areas. In summer especially, it also detects air masses with cleaner background levels arriving from the Gulf of Mexico. The SGP NOAA aircraft sampling site [Sweeney et al., in preparation; http://www.esrl.noaa.gov/gmd/ccgg/aircraft/] in northern Oklahoma is also used in the comparison study. At each aircraft site, twelve discrete air samples are collected at specified altitudes on a weekly or biweekly basis. Oklahoma is the fourth largest state for natural gas production in the USA [EIA, 2008] and one would expect to observe signatures of oil and gas drilling operations at both SGP and BAO. Additional information on the tower and aircraft programs is available at http://www.esrl.noaa.gov/gmd/ccgg/. Median summer mixing ratios for several alkanes, C_2H_2, C_6H_6 and CO are presented in the Results section.

2.3. Mobile Sampling

Two mobile sampling strategies were employed during this study. The first, the Mobile Lab, consisted of a fast response CO_2 and CH_4 analyzer (Picarro, Inc.), a CO gas-filter correlation instrument from Thermo Environmental, Inc., an O_3 UV-absorption analyzer from 2B Technologies and a Global Positioning System (GPS) unit. All were installed onboard a vehicle. A set of 3 parallel inlets attached to a rack on top of the vehicle brought in outside air from a few meters above the ground to the instruments. Another simpler sampling strategy was to drive around and collect flask samples at predetermined locations in the Front Range region. A summary of the on-road surveys is given in Table 2.

The Mobile Lab's Picarro Envirosense $CO_2/CH_4/H_2O$ analyzer (model G1301, unit CFADS09) employs Wavelength-Scanned Cavity Ring-Down Spectroscopy (WS-CRDS), a time-based measurement utilizing a near-infrared laser to measure a spectral signature of the molecule. CO_2, CH_4, and water vapor were measured at a 5-second sampling rate (0.2 Hz), with a standard deviation of 0.09 ppm in CO_2 and 0.7 ppb for CH_4. The sample was not dried prior to analysis, and the CO_2 and CH_4 mole fractions were corrected for water vapor after the experiment based on laboratory tests. For water mole fractions between 1% and 2.5%, the relative magnitude of the CH_4 correction was quasi-linear, with values between 1 and 2.6%. CO_2 and CH_4 mole fractions were assigned against a reference gas tied to the relevant World Meteorological Organization (WMO) calibration scale. Total measurement uncertainties were 0.1 ppm for CO_2 and 2 ppb for CH_4 [Sweeney et al., in preparation]. The CO and ozone data from the Mobile Lab are not discussed here. GPS data were also collected in the Mobile Lab at 1 Hz, to allow data from the continuous analyzers to be merged with the location of the vehicle.

The excursions with the flask sampler (PFP) focused on characterizing the concentrations of trace gases in Boulder (June 4 and 11, 2008), the northeastern Front Range (June 19), Denver (July 1) and around oil and gas wells and feedlots in Weld County south of Greeley (July 14) (see Table 2). Up to 24 sampling locations away from direct vehicle emissions were chosen before each drive.

Each Mobile Lab drive lasted from four to six hours, after a ~30 min warm-up on the NOAA campus for the continuous analyzer before switching to battery mode. The first two Mobile Lab drives, which did not include discrete air sampling, were surveys around Denver (July 9) and between Boulder and Greeley (July 15). The last two drives with the Mobile Lab (July 25 and 31) combined in-situ measurements with discrete flask sampling to target emissions from specific sources: the quasi-real-time display of the data from the continuous CO_2/CH_4 analyzer was used to collect targeted flask samples at strong CH_4 point sources in the vicinity of BAO. Discrete air samples were always collected upwind of the surveying vehicle and when possible away from major road traffic.

2.4. Chemical Analyses of Flask Samples

Discrete air samples were collected at BAO and during the road surveys with a two-component collection apparatus. One (PCP) includes pumps and batteries, along with an onboard microprocessor to control air sampling. Air was drawn through Teflon tubing attached to an expandable 3-m long fishing pole. The second package (PFP) contained a sampling manifold and twelve cylindrical, 0.7L, glass flasks of flow-through design, fitted with Teflon O-ring on both stopcocks. Before deployment, manifold and flasks were leak-checked then flushed and pressurized to ~1.4 atm with synthetic dry zero-air containing approximately 330 ppm of CO_2 and no detectable CH_4. During sampling, the manifold and flasks were flushed sequentially, at ~5 L min^{-1} for about 1 min and 10 L min^{-1} for about 3 minutes respectively, before the flasks were pressurized to 2.7 atm. Upon returning to the NOAA lab, the PFP manifold was leak-checked and meta-data recorded by the PFP during the flushing and sampling procedures were read to verify the integrity of each air sample collected. In case of detected inadequate flushing or filling, the affected air sample is not analyzed.

Samples collected in flasks were analyzed for close to 60 compounds by NOAA GMD (http://www.esrl.noaa.gov/gmd/ccgg/aircraft/analysis.html). In this paper, we focus on eight species: 5 alkanes (CH_4, C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12}) as well as CO, C_2H_2 and C_6H_6. CH_4 and CO in each flask were first quantified on one of two nearly identical automated analytical systems (MAGICC 1 & 2). These systems consist of a custom-made gas inlet system, gas-specific analyzers, and system-control software. Our gas inlet systems use a series of stream selection valves to select an air sample or standard gas, pass it through a trap for drying maintained at ~-80°C, and then to an analyzer.

CH_4 was measured by gas chromatography (GC) with flame ionization detection (±1.2 ppb = average repeatability determined as 1 s.d. of ~20 aliquots of natural air measured from a cylinder) [Dlugokencky et al., 1994]. We use the following abbreviations for measured mole fractions: ppm = µmol mol^{-1}, ppb = nmol mol^{-1}, and ppt = pmol mol^{-1}. CO was measured directly by resonance fluorescence at ~150 nm (±0.2 ppb) [Gerbig et al., 1999; Novelli et al., 1998]. All measurements are reported as dry air mole fractions relative to internally consistent calibration scales maintained at NOAA (http://www.esrl.noaa.gov/gmd/ccl/scales.html).

Gas chromatography/mass spectrometric (GC/MS) measurements were also performed on ~200 mL aliquots taken from the flask samples and pre-concentrated with a cryogenic trap at near liquid nitrogen temperatures [Montzka et al., 1993]. Analytes desorbed at ~110^{o}C were then separated by a temperature-programmed GC column (combination 25 m x 0.25 mm DB5 and 30 m x 0.25 mm Gaspro), followed by detection with mass spectrometry by monitoring compound-specific ion mass-to-charge ratios. Flask sample responses were calibrated versus whole air working reference gases which, in turn, are calibrated with respect to gravimetric primary standards (NOAA scales: benzene on NOAA-2006 and all other hydrocarbons (besides CH_4) on NOAA-2008). We used a provisional calibration for n-butane based on a diluted Scott Specialty Gas standard. Total uncertainties for analyses from the GC/MS reported here are <5% (accuracy) for all species except n-C_4H_{10} and C_2H_2, for which the total uncertainty at the time of this study was of the order of 15-20%. Measurement precision as repeatability is generally less than 2% for compounds present at mixing ratios above 10 ppt.

To access the storage stability of the compounds of interest in the PFPs, we conducted storage tests of typically 30 days duration, which is greater than the actual storage time of the samples used in this study. Results for C_2H_2 and C_3H_8 show no statistically significant enhancement or degradation with respect to our "control" (the original test gas tank results) within our analytical uncertainty. For the remaining species, enhancements or losses average less than 3% for the 30 day tests. More information on the quality control of the flask analysis data is available at http://www.esrl.noaa.gov/gmd/ccgg/aircraft/qc.html.

The flask samples were first sent to the GC/MS instrument for hydrocarbons, CFCs, and HFCs before being analyzed for major GHGs. This first step was meant to screen highly polluted samples that could potentially damage the greenhouse gas MAGICC analysis line with concentrations well above "background" levels. The time interval between flask collection and flask analysis spanned between 1 to 11 days for the GC/MS analysis and 3 to 12 days for MAGICC analysis.

3) Results

3.1 BAO tall tower: long-term sampling platform for regional emissions

3.1.1 Comparing BAO with other sampling sites in the US

Air samples collected at BAO tower have a distinct chemical signature (Figure 2), showing enhanced levels of most alkanes (C_3H_8, nC_4H_{10}, iC_5H_{12} and nC_5H_{12}) in comparison to results from other NOAA cooperative tall towers (see summary of site locations in Table 1 and data time series in Figure 1S). The midday summer time median mixing ratios for C_3H_8 and $n\text{-}C_4H_{10}$ at BAO were at least 6 times higher than those observed at most other tall tower sites. For $i\text{-}C_5H_{12}$ and $n\text{-}C_5H_{12}$, the summertime median mixing ratios at BAO were at least 3 times higher than at the other tall towers.

In Figure 2, we show nighttime measurements at the Niwot Ridge Forest tower (NWF) located at a high elevation site on the eastern slopes of the Rocky Mountains, 50 km west of BAO. During the summer nighttime, downslope flow brings clean air to the tower [Roberts et al., 1984]. The median summer mixing ratios at NWF for all the species shown in Figure 2 are much lower than at BAO, as would be expected given the site's remote location.

Similarly to BAO, the northern Oklahoma aircraft site, SGP, exhibits high alkane levels in the boundary layer and the highest methane summer median mixing ratio of all sites shown in Figure 2 (1889 ppb at SGP vs. 1867 ppb at BAO). As for BAO, SGP is located in an oil- and gas-producing region. Oklahoma, the fourth largest state in terms of natural gas production in the US, has a much denser network of interstate and intrastate natural gas pipelines compared to Colorado. Katzenstein et al. [2003] documented the spatial extent of alkane plumes around the gas fields of the Anadarko Basin in Texas, Oklahoma, and Kansas during two sampling intensives. The authors estimated that methane emissions from the oil and gas industry in that entire region could be as high as 4-6 Tg CH_4/yr, which is 13-20% of the US total methane emission estimate for year 2005 reported in the latest EPA US GHG Inventory [EPA, 2011a].

Enhancements of CH_4 at BAO are not as striking in comparison to other sites. CH_4 is a long-lived gas destroyed predominantly by its reaction with OH radicals. CH_4 has a background level that varies depending on the location and season [Dlugokencky et al., 1994], making it more difficult to interpret differences in median summer CH_4 mixing ratios at the suite of towers. Since we do not have continuous measurements of CH_4 at any of the towers except WGC, we cannot clearly separate CH_4 enhancements from background variability in samples with levels between 1800 and 1900 ppb if we only look at CH_4 mixing ratios by themselves (see more on this in the next section).

3.1.2 Influence of different sources at BAO

3.1.2.1. Median mixing ratios in the three wind sectors

To better separate the various sources influencing air sampled at BAO, Figure 3 shows the observed median mixing ratios of several species as a function of prevailing wind direction. For this calculation, we only used samples for which the associated 30-minute average wind speed (prior to collection time) was larger than 2.5 m/s. We separated the data into three wind sectors: NE, including winds from the north, northeast and east (wind directions between 345^o and 120^o); S, including south winds (120^o to 240^o); and W, including winds from the west (240^o to 345^o).

For the NE sector, we can further separate summer (June to August) and winter (November to April) data. For the other two wind sectors, only the winter months have enough data points. The species shown in Figure 3 have different photochemical lifetimes [Parrish et al., 1998], and all are shorter-lived in the summer season. This fact, combined with enhanced vertical mixing in the summer, leads to lower mixing ratios in summer than in winter.

Air masses from the NE sector pass over the oil and gas wells in the DJB and exhibit large alkane enhancements. In winter, median mole fractions of C_3-C_5 alkanes are 8 to 11 times higher in air samples from the NE compared to the samples from the W sector, while the median CH_4 value is 76 ppb higher. The NE wind sector also shows the highest median values of C_6H_6, but not CO and C_2H_2.

C_3H_8, n-C_4H_{10} and the C_5H_{12} isomers in air samples from the NE wind sector are much higher than in air samples coming from the Denver metropolitan area in the South wind sector. Besides being influenced by Denver, southern air masses may pass over two operating landfills, the Commerce City oil refineries, and some oil and gas wells (Figure 1). The S sector BAO CO and C_2H_2 mixing ratios are higher than for the other wind sectors, consistent with the higher density of vehicular emission sources [Harley et al., 1992; Warneke et al., 2007; Baker et al., 2008] south of BAO. There are also occasional spikes in CFC-11 and CFC-12 mixing ratios in the S sector (not shown). These are most probably due to leaks from CFC-containing items in the landfills. Air parcels at BAO coming from the east pass over Interstate Highway 25, which could explain some of the high mole fractions observed for vehicle combustion tracers such as CO, C_2H_2, and C_6H_6 in the NE sector data (see more discussion on C_6H_6 and CO in section 4.4 & Figure 4).

The W wind sector has the lowest median mole fractions for all anthropogenic tracers, consistent with a lower density of emission sources west of BAO compared to the other wind sectors. However, the S and W wind sectors do have some data points with high alkane values, and these data will be discussed further below.

3.1.2.2. Strong alkane source signature

To detect if the air sampled at BAO has specific chemical signatures from various sources, we looked at correlation plots for the species shown in Figure 3. Table 3 summarizes the statistics for various tracer correlations for the three different wind sectors. Figure 4 (left column) shows correlation plots of some of these BAO species for summer data in the NE wind sector.

Even though BAO data from the NE winds show the largest alkane mixing ratios (Figure 3), all three sectors exhibit strong correlations between C_3H_8, n-C_4H_{10} and the C_5H_{12} isomers (Table 3). The r^2 values for the correlations between C_3H_8 and n- C_4H_{10} or the C_5H_{12} isomers are over 0.9 for the NE and W sectors. CH_4 is also well correlated with C_3H_8 in the NE wind sector for both seasons. For the NE wind sector BAO summertime data, a min/max range for the C_3H_8/CH_4 slope is 0.099 to 0.109 ppb/ppb.

The tight correlations between the alkanes suggest a common source located in the vicinity of BAO. Since large alkane enhancements are more frequent in the NE wind sector, this common source probably has larger emissions north and east of the tower. This NE wind sector encompasses Interstate Highway 25 and most of the DJB oil and gas wells. The C_3-C_5 alkane mole fractions do not always correlate well with combustion tracers such as C_2H_2 and CO for the BAO NE wind sector ($C_{3\text{-}5}$/CO and $C_{3\text{-}5}/C_2H_2$: $r^2 <$ 0.3 for 50 summer samples; $C_{3\text{-}5}$/CO: r^2 <0.4 and $C_{3\text{-}5}/C_2H_2$: r^2 ~0.6 for 115 winter samples). These results indicate that the source responsible for the elevated alkanes at BAO is not the major source of CO or C_2H_2, which argues against vehicle combustion exhaust as being responsible. Northeastern Colorado is mostly rural with no big cities. The only operating oil refineries in Colorado are in the northern part of the Denver metropolitan area, south of BAO. The main industrial operations in the northeastern Front Range are oil and natural gas exploration and production and natural gas processing and transmission. We therefore hypothesize here that the oil and gas operations in the DJB, as noted earlier in Section 2, are a potentially substantial source of alkanes in the region.

3.1.2.3. At least two sources of benzene in BAO vicinity

The median winter C_6H_6 mixing ratio at BAO is higher for the NE wind sector compared to the South wind sector, which comprises the Denver metropolitan area. The C_6H_6-to-CO winter correlation is highest for the S and W wind sectors BAO samples (r^2=0.85 and 0.83 respectively) compared to the NE wind sector data (r^2=0.69). The C_6H_6-to-CO correlation slope is substantially higher for the NE wind sector data compared to the other two wind sectors, suggesting that there may be a source of benzene in the NE that is not a significant source of CO. The C_6H_6-to-C_2H_2 correlation slope is slightly higher for the NE wind sector data compared to the other two wind sectors. C_6H_6 in the BAO data from the NE wind sector correlates more strongly with C_3H_8 than with CO. The C_6H_6-to-C_3H_8 summer correlation slope for the NE wind sector is 10.1 ±1.2 ppt/ppb (r^2=0.67).

For the S and W wind sectors BAO data, the C_6H_6-to-C_2H_2 (0.27 - 0.32 ppt/ppt) and C_6H_6-to-CO (1.57 - 1.81 ppt/ppb) slopes are larger than observed emissions ratios for the Boston/New York City area in 2004: 0.171 ppt/ppt for C_6H_6-to-C_2H_2 ratio and 0.617 ppt/ppb for C_6H_6-to-CO ratio [Warneke et al., 2007]. Baker et al. [2008] report an atmospheric molar C_6H_6-to-CO ratio of 0.9 ppt/ppb for Denver in summer 2004, which is in between the Boston/NYC emissions ratio value reported by Warneke et al. [2007] and the BAO S and W wind sectors correlation slopes.

The analysis of the BAO C_6H_6 data suggests the existence of at least two distinct C_6H_6 sources in the vicinity of BAO: an urban source related mainly to mobile emissions, and a common source of alkanes and C_6H_6 concentrated in northeastern Colorado. We discuss C_6H_6 correlations and sources in more detail in section 4.4.

3.2. On-road surveys: tracking point and area source chemical signatures

Road surveys with flask sampling and the Mobile Lab with the fast-response CH_4 analyzer were carried out in June-July 2008 (Table 2). The extensive chemical analysis of air samples collected in the Front Range provides a snapshot of a broader chemical composition of the regional boundary layer during the time of the study. The Mobile Lab surveys around the Front Range using the in situ CH_4 analyzer allowed us to detect large-scale plumes with long-lasting enhancements of CH_4 mixing ratios as well as small-scale plumes associated with local CH_4 point sources. In the last two Mobile Lab surveys (surveys 8 and 9), we combined the monitoring of the continuous CH_4 analyzer with targeted flask sampling, using the CH_4 data to decide when to collect flask samples in and out of plumes.

The regional background CH_4 mixing ratio at the surface (interpreted here as the lowest methane level sustained for ~10 minutes or more) was between 1800 ppb and 1840 ppb for most surveys. Some of the highest "instantaneous" CH_4 mixing ratios measured during the Mobile Lab surveys were: 3166 ppb at a wastewater treatment plant, 2329 ppb at a landfill, 2825 ppb at a feedlot near Dacono, over 7000 ppb close to a feedlot waste pond near Greeley, and 4709 ppb at a large natural gas processing and propane plant in Fort Lupton (Figure 1).

The analysis of the summer 2008 intensive data suggests that regional scale mixing ratio enhancements of CH_4 and other alkanes are not rare events in the Colorado Northern Front Range airshed. Their occurrence and extent depends on both emissions and surface wind conditions, which are quite variable and difficult to predict in this area. During the Mobile Lab road surveys, the high-frequency measurements of CO_2 and CH_4 did not exhibit any correlation. Unlike CO_2, the CH_4 enhancements were not related to on-road emissions. Below we present two examples of regional enhancements of CH_4 observed during the Front Range Mobile Lab surveys.

3.2.1. Survey 9: C_{3-5} alkane levels follow large-scale changes in methane

Figure 5 shows a time series of the continuous CH_4 mixing ratio data and alkane mixing ratios measured in twelve flask samples collected during the Front Range Mobile Lab survey on 31 July 2008 (flasks #1 to 12, sampled sequentially as shown in Figure 6). The wind direction on that day was from the ENE or E at the NCAR Foothills Lab and BAO tower. The Mobile Lab left the NOAA campus in Boulder around 11:40 am and measured increasing CH_4 levels going east towards the BAO tower (Figure 6). An air sample was collected close to the peak of the CH_4 broad enhancement centered around 11:55 am. The CH_4 mixing ratio then decreased over the next 25 minutes and reached a local minimum close to 1875 ppb. The CH_4 level stayed around 1875 ppb for over one hour and then decreased again, more slowly this time, to ~ 1830 ppb over the next two hours.

Flasks # 1 to 3 were collected before, at the peak, and immediately after the broad CH_4 feature between 11:40 and 12:15. Flasks # 4 & 5 were sampled close to a wastewater treatment plant and flasks # 7 to 8 were sampled in a landfill. The in situ measurements showed that CH_4 was still elevated above background as these samples were collected. After a 90-minute stop at BAO to recharge the Mobile Lab UPS batteries, flasks # 9 to 11 were collected in a corn field while the in situ measurements showed lower CH_4 levels. The last flask sample was collected on the NOAA campus just before 17:00 MDT, about 5.5 hours after the first flask sample was collected. The flask samples were always collected upwind of the Mobile Lab car exhaust.

Sharp spikes in the continuous CH_4 data reflect local point sources (wastewater treatment plant, landfill). The highly variable signals in both the continuous and discrete CH_4 close to these sources are driven by the spatial heterogeneity of the CH_4 emissions and variations in wind speed and direction. Broader enhancements in the continuous CH_4 data reflect larger (regional) plumes. The last flask (#12) sampled at NOAA has much higher levels of combustion tracers (CO, C_2H_2, C_6H_6) than the other samples.

Figure 7 shows correlation plots for C_3H_8 versus CH_4 and n-C_4H_{10} versus C_3H_8 in the 12 flasks taken on 31 July. Air samples not directly influenced by identified point sources (flasks #1-3, 6-7, 9-12) show a very strong correlation between the various measured alkanes. Using the data from the air samples not directly influenced by identified point sources (flasks #1-3, 6-7, 9-12), we derive a C_3H_8-to-CH_4 (C_3/C_1) mixing ratio slope of 0.097± 0.005 ppb/ppb (Figure 7A). This slope is very similar to the one observed for the summertime NE wind sector data at BAO (0.104± 0.005; Table 3). Three air samples collected downwind of the waste water treatment plant and the landfill (flasks # 4-5 and 8) are off the C_3H_8-to-CH_4 correlation line and have higher CH_4 than air samples collected nearby but not under the influence of these local CH_4 sources (flasks 3 and 6). Flask # 8 also has elevated CFC-11 (310 ppt) compared to the other samples collected that day (< 255 ppt), probably related to leaks from old appliances buried in the landfill.

The C_3-C_5 alkane mixing ratios in samples collected on 31 July are tightly correlated for flasks # 1 to 11 with $r^2 > 0.95$ (Figure 7B). As concluded for the BAO alkane mixing ratio enhancements earlier, this tight correlation suggests that the non-methane alkanes measured during the surveys are coming from the same source types. The nC_4/C_3 correlation slope on 31 July (0.47 ppb/ppb; flasks # 1-11) is similar to the summer slope in the BAO NE samples (0.45 ppb/ppb), while the 31 July iC_5/C_3 and nC_5/C_3 slopes are slightly higher (0.17 and 0.17 ppb/ppb, respectively) than for BAO (0.14 and 0.15 ppb/ppb, respectively).

3.2.2. Survey 6: Alkane enhancements in the Denver-Julesburg oil and gas production zone and cattle feedlot contributions to methane

The flask-sampling-only mobile survey on 14 July 2008 focused on the agricultural and oil and gas drilling region south of Greeley. Eleven of the twelve air samples collected on 14 July were taken over the Denver-Julesburg Basin (flasks# 2-12 in Figure 3S in Supplementary Material). Figure 8A shows a correlation plot of C_3H_8 versus CH_4 mixing ratios in these air samples. Flasks collected NE of BAO and not near feedlots (# 4, 6-8, and 10-12) fall on a line: y=0.114(x-1830) (r^2=0.99). This slope and the correlation slope calculated for the BAO NE wind sector data are indistinguishable (within the 1-σ uncertainties in the slopes). Four samples collected in the vicinity of four different cattle feedlots (flasks # 2, 3, 5, and 9) exhibit a lower C_3H_8-to-CH_4 correlation slope (0.083 ppb/ppb, r^2=0.93). The r^2 for the C_3H_8-to-CH_4 correlation using all the flasks is 0.91.

The n-C_4H_{10} versus C_3H_8 correlation plot and its slope, along with the n-C_4H_{10}–to-C_3H_8 and C_5H_{12}–to-C_3H_8 correlation slopes for air samples not collected downwind of feedlots are shown in Figure 8B. The r^2 for the n-C_4H_{10}-to-C_3H_8 correlation using all the flasks is 0.98, which is slightly higher than the r^2 for the C_3H_8-to-CH_4 correlation using all flasks (0.91). The r^2 for the i-C_5H_{12}-to-n-C_4H_{10} and n-C_5H_{12}-to-n-C_4H_{10} correlations using all the flasks are 0.96 ppb/ppb and 0.99 ppb/ppb, respectively. These results suggest that cattle feedlots have no substantial impact on n-C_4H_{10} and the C_5H_{12} levels.

The strong correlation observed between the various alkane mixing ratios for air samples not collected downwind of feedlots once again suggests that a common source contributes to most of the observed alkanes enhancements. It is possible that some of the C_3H_8 enhancements seen near the feedlots are due to leaks of propane fuel used for farm operations [Ronald Klusman, personal communication]. Two flask samples were collected downwind of a cattle feedlot near Dacono during Mobile Lab survey #8, on 25 July 2008. The analysis of these samples revealed large CH_4 enhancements (1946 and 2335 ppb), but no enhancement in C_3H_8 (~ 1ppb), n-C_4H_{10} (<300ppt), the C_5H_{12} (< 130ppt) or C_6H_6 (< 30ppt).

For survey #6, the n-C_4H_{10}-to-C_3H_8 correlation slope (0.56 ppb/ppb) is 16% higher than the summer slope observed at BAO for the NE wind sector data, while the 14 July i-C_5H_{12}-to-C_3H_8 and n-C_5H_{12}-to-C_3H_8 correlation slopes (0.24 and 0.23 ppb/ppb, respectively) are 76% and 53% higher, respectively, than the summer NE BAO data. These slopes are higher than for flasks from survey #9. The difference in the C_5/C_3 slopes between the various Mobile Lab surveys data and the BAO NE summer data may reflect the spatial variability in the alkane source molar composition.

3.2.3. Benzene source signatures

To look at the C_6H_6 correlations with other tracers, the 88 Mobile Lab flask samples have been divided into two subsets, none of which includes the three samples collected downwind of the natural gas and propane processing plant near Dacono, CO. In the summer, the lifetimes of C_6H_6 and C_3H_8 at 800 mbar and 40^{o}N are close to 3 or 4 days and the lifetime of CO is about 10 days [Finlayson-Pitts and Pitts, 2000; Spivakovsky et al., 2000].

The first subset of 39 samples has C_3H_8 mixing ratios smaller than 3 ppb and it includes flasks collected mostly during surveys #2, 3 and 4. For this subset influenced mostly by urban and mobile emissions, C_6H_6 correlates well with CO (slope=1.82 ppt/ppb, r^2=0.89) and C_2H_2 (slope=0.37 ppt/ppt, r^2=0.75) but not with C_3H_8 (r^2<0.3). The C_6H_6-to-CO correlation slope for this subset is similar to the correlation slopes for the BAO S and W wind sector winter samples.

The second subset of 46 samples corresponds to flasks with a C_3H_8 mixing ratio larger than 3ppb. These flasks were collected mostly during surveys #1, 6, 8 and 9. For this second subset influenced mostly by emissions from the DJB, C_6H_6 correlates well with C_3H_8 (slope=17.9 ppt/ppb, r^2=0.95) but not with CO or C_2H_2 (r^2<0.3). The C_6H_6-to-

C_3H_8 slope for these samples is almost twice as big as the slope calculated for the BAO NE wind sector data (10.1 ppt/ppb) (Table 3).

4) Discussion

4.1. Comparing the alkane enhancements in the BAO and Mobile Lab data sets

In the previous section we showed two examples of enhanced alkanes in northeast Colorado using mobile sampling (surveys 6 and 9 on 14 and 31 July 2008, respectively). With lifetimes against OH removal on the order of 3.5, 1.7 and 1.0 days in the summer at 40^{o}N [Finlayson-Pitts and Pitts, 2000; Spivakovsky et al., 2000] respectively, C_3H_8, n-C_4H_{10} and the C_5H_{12} isomers do not accumulate over the continent. Instead their atmospheric mixing ratios and the slopes of correlations between different alkanes reflect mostly local or regional sources within a few days of atmospheric transport.

The source responsible for the alkane enhancements observed at BAO and in multiple surveys during the Front Range Study appears to be located in the northeastern part of the Front Range region within the Denver-Julesburg Basin, so we call it the DJB source. The small differences in alkane correlation slopes for the BAO and Mobile Lab samples likely reflect differences in the emitted alkane molar ratios across this distributed source, as well as the mix of chemical ages for the air samples collected at a variety of locations and on different days.

In Table 3 and Figure 4, we compare the alkane correlation slopes in the Mobile Lab flask data set with the correlation slopes in the BAO data set. To calculate the DJB source C_3H_8-to-CH_4 correlation slope from the Mobile Lab data set, we have removed air samples collected downwind of feedlots, the wastewater treatment plant, and the natural gas and propane processing plant (Figure 1). The Mobile Lab flasks C_3H_8-to-CH_4 correlation slope is 0.095±0.007 ppb/ppb (R^2=0.76, 77 samples), similar to the slope calculated for the BAO NE wind sector data. Samples collected downwind of the natural gas processing plant exhibit variable chemical signatures, reflecting a complex mix of contributions from leaks of gas and combustion exhaust from flaring units and compressor engines.

To calculate the DJB source n-C_4H_{10}-to-C_3H_8, i-C_5H_{12}-to-C_3H_8 and n-C_5H_{12}-to-C_3H_8 correlation slopes from the Mobile Lab data set, we have removed the three air samples collected downwind of the natural gas and propane processing plant (Figure 1). The C_4/C_3, i-C_5/C_3 and n-C_5/C_3 correlation slopes in the Mobile Lab data are 0.49, 0.19 and 0.19 ppb/ppb, respectively (r^2> 0.8, 85 samples). The i-C_5/C_3 and n-C_5/C_3 correlation slopes are 40% and 30% higher, respectively, than the BAO NE sector summer slopes. If we remove the 11 data points from survey #6 samples collected in the middle of the DJB, the C_5H_{12}-to-C_3H_8 ratios are only 15% higher than calculated for the NE sector at BAO.

High correlations among various alkanes were reported in this region by Goldan et al. [1995]. In that study, hourly air samples were analyzed with an in-situ gas chromatograph deployed on a mesa at the western edge of Boulder for two weeks in

February 1991. CH_4 was not measured during that study. The correlation coefficient (r^2) between C_3H_8, n-C_4H_{10}, and the C_5H_{12} isomers was around 0.86, with a clear minimum slope for the abundance ratios (see Figure 4 in Goldan et al. [1995]). The authors proposed that the C_4-C_6 alkanes shared one common source with propane (called the "C_3 source" in the next section and in Figure 9), with additional emissions contributing to some C_4-C_6 alkane enhancements.

4.2. Comparing the Front Range observed alkane signatures with VOC emissions profiles for oil and gas operations in the Denver-Julesburg Basin

In this section we compare the alkane ratios calculated from the BAO NE wind sector and the Mobile Lab samples to emissions profiles from the DJB oil and gas exploration and production sector. Most of these profiles were provided by the WRAP Phase III inventory team, who developed total VOC and NOx emission inventories for oil and gas production and processing operation in the DJB for 2006 [Bar-Ilan et al., 2008a]. Emissions and activity data were extrapolated by the WRAP Phase III inventory team to derive emission estimates for 2010 based on projected production numbers and on state and federal emissions control regulations put in place in early 2008 for oil and gas permitted activities in the DNFR NAA [Bar-Ilan et al., 2008b]. The VOCs included in the inventories are: C_3H_8, i,n-C_4H_{10}, i,n-C_5H_{12} and higher alkanes, C_6H_6, toluene, ethyl-benzene, xylenes and 224-trimethylpentane. The WRAP Phase III inventories for 2006 and 2010 were only provided as total VOC and NOx emitted at the county level for all the counties in the Colorado part of the DJB. The emission estimates are based on various activity data (including the number of new wells (spuds), the total number of wells, estimates of oil, condensate and gas production, and equipment counts) and measured/reported or estimated VOC speciation profiles for the different source categories. Supplementary Figure 2S and Bar-Ilan et al. [2008a,b] present more details on how the inventory emission estimates are derived.

We focus primarily on flashing and venting sources here, since the WRAP Phase III inventory indicates that these two sources are responsible for 95% of the total VOC emissions from oil and gas exploration and production operations in Weld County and in the NAA [Bar-Ilan et al., 2008a,b] (see Figure 2S). In 2006, all the oil produced in the DJB was from condensate wells. Condensate tanks at well pads or processing plants store a mostly-liquid mix of hydrocarbons and aromatics separated from the lighter gases in the raw natural gas. Flash losses or emissions happen for example when the liquid condensate is exposed to decreasing atmospheric pressure: gases dissolved in the liquid are released and some of the heavier compounds may be entrained with these gases. Flashing emissions from condensate storage tanks are the largest source of VOCs from oil and gas operations in the DJB. In the DNFR NAA, operators of large condensate tanks have to control and report emission estimates to the Colorado Department of Public Health and the Environment (CDPHE). In 2006 and 2010 flashing emissions represented 69% and 65% respectively of the total VOC source from oil and gas exploration, production and processing operations, for the nine counties in the NAA (see supplementary Figure 2S and Bar-Ilan et al. [2008a] for more details on how the estimates are derived).

Venting emissions are related to loss of raw natural gas when a new oil or gas well is drilled or when an existing well is vented (blowdown), repaired or restimulated (recompletion). Equipment at active well sites (e.g. well head, glycol dehydrators and pumps) or in the midstream network of compressors and pipelines gathering the raw natural gas can also leak significant amounts of natural gas. In the WRAP Phase III inventory, venting emissions represented 27% and 21% respectively of the total VOC estimated source from the NAA oil and gas operations in 2006 and 2010 ([Bar-Ilan et al., 2008a,b], Figure 2S).

The molar compositions of venting and flashing emissions are quite different (see supplementary Figure 4S). Emissions from flash losses are enriched in C_{2+} alkanes compared to the raw natural gas emissions. To convert the total VOC bottom-up source into speciated emission ratio estimates, we use molar ratio profiles for both flashing and venting emissions reported in three data sets:

- Bar-Ilan et al. [2008a]: mean venting profile used for the 2006 DJB inventory, also called the "Venting-WRAP" profile;
- Colorado Oil and Gas Conservation Commission [COGCC, 2007]: composition of 77 samples of raw natural gas collected at different wells in the Greater Wattenberg Area in December 2006, also called "Venting-GWA" profiles. Note that C_6H_6 was not reported in this data set;
- Colorado Department of Public Health and the Environment (CDPHE, personal communication): flashing emissions profiles based on condensate composition data from 16 different storage tanks in the DJB and EPA TANK2.0 (flashing emissions model) runs.

Figure 9 shows a comparison of the alkane molar ratios for the raw natural gas and flash emissions data sets with the correlation slopes derived for the Mobile Lab 2008 samples and for air samples collected at BAO in the summer months only (between August 2007 and April 2010) for the NE wind sector (cf. Table 4S to get the plotted values). The alkane correlation slopes observed at BAO and across the Northern Front Range with the Mobile Lab are all within the range of ratios reported for flashing and/or venting emissions. The C_{3-5} alkane ratios for both flashing and venting emissions are too similar for their atmospheric ratios to be useful in distinguishing between the two source processes. The ambient C_3H_8-to-CH_4 and n-C_4H_{10}-to-CH_4 molar ratios are lower than what could be expected from condensate tank flashing emissions alone, indicating that most of the CH_4 observed came from the venting of raw natural gas. In the next section, we will describe how we derive bottom-up emission estimates for CH_4 and C_3H_8 as well as three top-down emissions scenarios consistent with the observed atmospheric slopes.

Figure 9 also shows the correlation slopes calculated by Goldan et al. [1995] for the 1991 Boulder study. These slopes compare very well with the BAO and Mobile Lab results and the oil and gas venting and flashing emissions ratios. Goldan et al. [1995] compared the measured C_4/C_3 and C_5/C_3 ratios for the Boulder C_3 source (see definition in Section 4.1) with the ratios reported in the locally distributed pipeline-quality natural gas for February 1991, and concluded that the common C_3H_8 and higher alkane source was not linked with the local distribution system of processed natural gas. However, the composition of the raw natural gas at the extraction well is quite different from the purified pipeline-quality natural gas distributed to end-users. Processed pipeline-quality natural gas delivered throughout the USA is almost pure CH_4 [Gas Research Institute, 1992]. Since Goldan et al. [1995] did not measure CH_4 in their 1991 study, they could not determine if the atmospheric C_{3+}/C_1 alkane ratios were higher than expected in processed natural gas.

4.3. Estimation of the alkane source in Weld County

Bottom-up speciated emission estimates

In this section, we derive bottom-up and top-down estimates of alkane emissions from the DJB source for Weld County. We have averaged the 2006 and 2010 WRAP Phase III total VOC emissions data [Bar-Ilan et al., 2008ab] to get bottom-up estimates for the year 2008, resulting in 41.3 Gg/yr for flashing emissions and 16.8 Gg/yr for venting emissions. There are no uncertainty estimates provided in the WRAP Phase III inventory. 2006 total VOC flashing emission estimates in Weld County are based on reported emissions for controlled large condensate tanks (34.8 Gg/yr) and calculated emissions for uncontrolled small condensate tanks (5.4 Gg/yr) (see [Bar-Ilan et al., 2008] for more details). Uncertainties attached to these estimates may be due to inaccurate emissions factors (number of pounds of VOC flashed per tons of condensate produced) and/or inaccurate estimate of the effectiveness of emission control systems.

The WRAP Phase III total VOC emission from venting sources for Weld County was calculated by averaging industry estimates of the volume of natural gas vented or leaked to the atmosphere by various processes shown in Figure 2S (well blowdown, well completion, pneumatic devices…). A basin-wide average of gas composition analyses provided by oil and gas producers was then used to compute a bottom-up estimate of the total mass of VOC vented to the atmosphere by oil and gas exploration, production and processing operations. Uncertainties attached to the venting source can be related to uncertainties in leak rates or intensity of out-gassing events, as well to the variability in the composition of raw natural gas, none of which were quantitatively taken into account in the WRAP Phase III inventory.

Next we describe the calculations, summarized in Figure 5S, to derive bottom-up estimates of venting and flashing emissions for the various trace gases we measured using information from the WRAP Phase III inventory and the COGCC GWA raw natural gas composition data set (Table 4 and supplementary Figure 6S). From the total annual vented VOC source and the average vented emission profile provided by Bar-Ilan et al. [2008a] (Table 2S), we derived an estimate of the volume of natural gas that we assumed is vented to the atmosphere by the oil and gas production and processing operations in Weld County. Following Bar-Ilan et al. inventory data and assumptions [2008a], we used the weight fraction of total VOC in the vented gas (18.74%), the molar mass of the vented gas (21.5g/mol) and standard pressure and temperature with the ideal gas law to assume that 1 mole of raw natural gas occupies a volume 22.4 L (as was done in the WRAP Phase III inventory). The total volume of vented gas we calculate for Weld County in 2008 is 3.36 billion cubic feet (Bcf), or the equivalent of 1.68% of the total natural gas produced in the county in 2008 (202.1 Bcf). We then use the estimate of the volume of vented gas and the molar composition profiles for the 77 raw natural gas samples reported in the COGCC GWA study to compute average, minimum, and maximum emissions for CH_4, each of the $C_{3\text{-}5}$ alkanes we measured, and C_6H_6. Using this procedure, 2008 Weld County average venting CH_4 and C_3H_8 bottom-up source estimates are 53.1 Gg/yr and 7.8 Gg/yr, respectively (Table 4).

For flashing emissions, we distributed the WRAP 2008 total annual VOC source estimate (41.3 Gg/yr) using the modeled flash loss composition profiles for 16 different condensate tanks provided by the CDPHE. Average CH_4 and C_3H_8 emissions as well as the minimum and maximum estimates are reported in Table 4. The 2008 average flashing CH_4 and C_3H_8 bottom-up emission estimates are 11.2 Gg/yr and 18.3 Gg/yr, respectively (Table 4). The total flashing + venting CH_4 and C_3H_8 bottom-up estimates range from 46 to 86 Gg/yr and from 15 to 52 Gg/yr, respectively.

Top-Down emissions scenarios

Finally, we use our atmospheric measurements to bring new independent constraints for the estimation of venting and flashing emissions in Weld County in 2008. The exercise consists in calculating three top-down venting emission scenarios for CH_4 and C_3H_8 (x_m, x_p: mass of methane and propane vented respectively) consistent with a mean observed CH_4-to-C_3H_8 atmospheric molar ratio of 10 ppb/ppb (Table 4) in the DJB. We assume, as done earlier in the bottom-up calculations, that the observed C_3H_8-to-CH_4 ratio in the DJB results from a combination of flashing and venting emissions. The bottom-up information used here is (1) the set of speciated flashing emissions derived earlier for the 16 condensate tanks provided by CDPHE for CH_4 and C_3H_8 $(y_m, y_p)_{\text{tank}=1,16}$, and (2) three scenarios for the basin-average raw (vented) natural gas CH_4-to-C_3H_8 molar ratio, denoted $v_{m/p}$. The three values used for basin-average vented gas CH_4-to-C_3H_8 molar ratio are: 18.75, which is the WRAP Phase III inventory assumption (scenario 1);

15.43, which is the median of the molar ratios for the COGCC GWA 77 gas samples (scenario 2); and 24.83, which is the mean of the molar ratios for the COGCC GWA 77 gas samples (scenario 3). For each vented gas profile scenario, we use the set of 16 flash emission estimates to calculate an ensemble of venting emission estimates for CH_4 (x_m) and C_3H_8 (x_p) following the two equations below.

The first equation formalizes the assumption for CH_4-to-C_3H_8 molar ratio of the vented raw natural gas, with M_m (16g/mol) and M_p (44g/mol) being the molar masses of CH_4 and C_3H_8 respectively.:

$$v_{m/p} = \frac{M_p}{M_m} \times \frac{x_m}{x_p} \qquad (1)$$

In the second equation, the mean observed atmospheric CH_4-to-C_3H_8 molar ratio ($a_{m/p}$=10 ppb/ppb) constrains the overall ratio of methane versus propane emitted by both flashing and venting sources. Therefore, for each set of 16 bottom-up flashed emission estimates (y_m, y_p), we have:

$$\frac{M_p\left(x_m + y_m\right)}{M_m\left(x_p + y_p\right)} = a_{m/p} \qquad (2)$$

The analytical solutions to this set of equations are given by:

$$\begin{aligned} x_p &= \frac{1}{\left(v_{m/p} - a_{m/p}\right)} \times \left(a_{m/p} \times y_p - \frac{M_p}{M_m} y_m\right) \\ x_m &= v_{m/p} \times \frac{M_m}{M_p} \times x_p \end{aligned} \qquad (3)$$

The average, minimum and maximum venting emission estimates, x_m and x_p, are reported for the three vented gas profile scenarios in Table 4 and Figure 10.

The first goal of this top-down estimation exercise is to highlight the many assumptions required to build the bottom-up and top-down emission estimates. The choices made for the WRAP Phase III inventory or our top-down calculations are all reasonable, and the uncertainty attached to the values chosen (if available) should be propagated to calculate total uncertainty estimates for the final emission products. When the error propagation is done conservatively, the emission uncertainty is close to a factor of 2 for both CH_4 and C_3H_8. This number is much higher than the 30% uncertainty reported by the EPA for the 2009 national CH_4 source estimate from natural gas systems [EPA, 2011c].

The scenario 1 mean top-down vented CH_4 source (118.4 Gg/yr) is twice as large as the bottom-up estimate of 53.1 Gg/yr (Table 4). If we assume that 77% (by volume) of the raw gas is CH_4, an average estimate of 118.4 Gg/yr of CH_4 vented would mean that the equivalent of 4% of the 2008 natural gas gross production in Weld County was vented. It is important to note that the top-down scenarios cover a large range (67-229 Gg/yr), corresponding to between 2.3% and 7.7% of the annual production being lost to the atmosphere through venting (Table 4). The lowest estimate is, however, larger than what we derived from the WRAP Phase III bottom-up inventory (1.68%). If instead of using the EIA [EIA, 2004] convention for the molar volume of gas (23.6 L/mol), we used the standard molar volume used by WRAP (22.4 L/mol), our top-down calculations of the volume of gas vented would be 5% lower than reported in Table 4.

Emissions for the other alkanes measured are all derived from the C3H8 total sources scaled with the atmospheric molar ratios observed in the BAO NE summer samples and the Mobile Lab samples. Figure 10 shows a comparison of the bottom-up estimates and the top-down emission scenarios (mean of scenario 1 and overall minimum and maximum of the three scenarios).

The main result of this exercise is that for each of the three top-down total emissions scenarios, the mean estimates for CH_4, n-C_4H_{10} and the C_5H_{12} isomers are at least 60% higher than the bottom-up mean estimates. The minimum top-down emissions scenarios are lower than (in the case of C_3H_8) or higher than (for CH_4, nC_4H_{10}, i-C_5H_{12}, n-C_5H_{12}) the bottom-up mean estimates.

To put the top-down CH_4 source estimate from oil and gas exploration, production and processing operations in perspective, we compare it with an estimate of the passive "geological" CH_4 flux over the entire DJB. Klusman and Jakel [1998] reported an average flux of 0.57 mg CH_4/m^2/day in the DJB due to natural microseepage of light alkanes. Multiplied by a rough upper boundary estimate of the DJB surface area (Figure 1), the estimated annual natural flux is 0.66 Gg CH_4 /yr, or less than 1% of the top-down venting source estimated for active exploration and production of natural gas in Weld County.

4.4. Benzene sources in the Northern Front Range

On-road vehicles are estimated to be the largest source of C_6H_6 in the US [EPA, 2009a]. Emissions from on-road and off-road vehicles and from large point sources (including chemical plants and refineries) have been regulated by the EPA for over thirty years [Fortin et al., 2005; Harley et al., 2006]. When motor vehicle combustion dominates emissions, such as in the BAO S and W wind sectors, C_6H_6 correlates well with CO and C_2H_2.

Crude oil and natural gas production and processing emitted an estimated 8333 tonnes of benzene nationally in 2005, which represented 2% of the national total C_6H_6

source [EPA, 2009a]. C_6H_6 and C_3H_8 have similar photochemical lifetimes (~ 3-4 days in the summer), so the observed atmospheric ratios we report in Table 3 should be close to their emission ratio if they are emitted by a common source. The strong correlation between C_6H_6 and C_3H_8 (Figure 4, Table 3) for the BAO NE wind sector and in the DJB Mobile Lab air samples suggests that oil and gas operations could also be a non-negligible source of C_6H_6 in the Northern Colorado Front Range.

The C_6H_6-to-C_3H_8 molar ratios in the flash losses from 16 condensate tanks simulated with the EPA TANK model are between 0.4 to 5.6 ppt/ppb. The C_6H_6-to-C_3H_8 molar ratio reported for vented emissions in the WRAP Phase III inventory is 5.3 ppt/ppb, based on regionally averaged raw gas speciation profiles provided by local companies [Bar-Ilan et al., 2008a] (only an average profile was provided, other data is proprietary). These emission ratios are at least a factor of two lower than the atmospheric ratios measured in the Front Range air samples influenced by the DJB source (Table 3).

If we use the mean C_3H_8 emission estimate for scenario 1 described in Section 4.3 (35.7 Gg/yr), together with the C_6H_6-to-C_3H_8 correlation slope for the summer BAO NE wind sector data and that from the Mobile Lab samples (10.1 ppt/ppb and 17.9 ppt/ppb respectively), we derive a C_6H_6 emission estimate for the DJB source in Weld County in 2008 of 639 tonnes/yr (min/max range: 478/883 tonnes/yr) and 1145 tonnes/yr (min/max range: 847/1564 tonnes/yr), respectively. As expected, these numbers are much higher than what we derived for the bottom-up flashing and venting emissions (total of 139 tonnes/yr, min/max range of 49-229 tonnes/yr). For comparison, C_6H_6 emissions from facilities in Colorado reporting to the US EPA for the Toxics Release Inventory amounted to a total of 3.9 tonnes in 2008 [EPA, 2009b] and on–road emissions in Weld

County were estimated at 95.4 tonnes/yr in 2008 [CDPHE, personal communication]. Based on our analysis, oil and gas operations in the DJB could be the largest source of C_6H_6 in Weld County.

More measurements are needed to further evaluate the various potential sources associated with oil and gas operations (for example, glycol dehydrators and condensate tank flash emissions). The past two iterations of the C_6H_6 emissions inventory developed by the State of Colorado for the National Emissions Inventory and compiled by the EPA do not show much consistency from one year to another. The 2008 and 2005 NEI reported very different C_6H_6 emission estimates for condensate tanks in Weld County (21.5 Mg/yr versus 1120 Mg/yr, respectively; see also Table 3S). Estimates in the 2008 NEI are much closer to estimates provided by CDPHE (personal communication) for 2008 (21.3 Mg/yr), suggesting the 2005 NEI estimate may be flawed, even though it is in the range of our top-down estimation. We conclude that the current level of understanding of emissions of C_6H_6 from oil and gas operations cannot explain the top-down range of estimates we derive in our study, suggesting that, once again, more field measurements are needed to understand and quantify oil and gas operation sources.

5) Conclusion

This study provides a regional overview of the processes impacting ambient alkane and benzene levels in northeastern Colorado in the late 2000s. We report atmospheric observations collected by two sampling platforms: a 300-m tall tower located in the SW corner of Weld County (samples from 2007 to 2010), and road surveys by a Mobile Lab equipped with a continuous methane analyzer and discrete canister sampling (June-July 2008). The analysis of the tower data filtered by wind sector reveals a strong alkane and benzene signature in air masses coming from northeastern Colorado, where the main activity producing these compounds is related to oil and gas operations over the Denver–Julesburg Fossil Fuel Basin. Using the Mobile Lab platform, we sampled air directly downwind of different methane sources (oil and gas wells, a landfill, feedlots, and a waste water treatment plant) and collected targeted air samples in and out of plumes. The tall tower and Mobile Lab data both revealed a common source for air masses with enhanced alkanes. In the data from both platforms, the alkane mixing ratios were strongly correlated, with slight variations in the correlation slopes depending on the location and day of sampling. The alkanes did not correlate with combustion tracers such as carbon monoxide and acetylene. We hypothesize that the observed alkanes were emitted by the same source located over the Denver-Julesburg Basin, "the DJB source".

The second part of the study brings in information on VOC emissions from oil and gas activities in the DJB from the detailed bottom-up WRAP Phase III inventory [Bar Ilan et al., 2008a,b]. We have used the total VOC emission inventory and associated emissions data for DJB condensate and gas production and processing operations to calculate annual emission estimates for CH_4, C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12} and C_6H_6 in Weld County. The main findings are summarized below:

- The emissions profiles for flashing and venting losses are in good agreement with the atmospheric alkane enhancement ratios observed during this study and by Goldan et al. [1995] in Boulder in 1991. This is consistent with the hypothesis that the observed alkane atmospheric signature is due to oil and gas operations in the DJB.

- The three top-down emission scenarios for oil and gas operations in Weld County in 2008 give a rather large range of potential emissions for CH_4 (71.6-251.9 Gg/yr) and the higher alkanes. Except for propane, the lowest top-down alkanes emission estimates are always larger than the inventory-based mean estimate we derived based on the WRAP Phase III inventory data and the COGCC GWA raw gas composition data set.
- There are notable inconsistencies between our results and state and national regulatory inventories. In 2008 gas wells in Weld County represented 15% of the state's production. Based on our top-down analysis, Weld County methane emissions from oil and gas production and processing represent at least 30% of the state total methane source from natural gas systems derived by Strait et al. [2007] using the EPA State Inventory Tool. The methane source from natural gas systems in Colorado is most likely underestimated by at least a factor of two. Oil and gas operations are the largest source of alkanes in Weld County. They were included as a source of "total VOC" in the 2008 EPA NEI for Weld County but not in the 2005 NEI.
- There are at least two main sources of C_6H_6 in the region: one related to combustion processes, which also emit CO and C_2H_2 (engines and mobile vehicles), and one related to the DJB alkane source. The C_6H_6 source we derived based on flashing and venting VOC emissions in the WRAP inventory (143 Mg/yr) most likely underestimates the actual total source of C_6H_6 from oil and gas

operations. Our top-down source estimates for C_6H_6 from oil and gas operations in Weld County cover a large range: 385-2056 Mg/yr. Again, the lowest figure is much higher than reported in the 2008 CDPHE inventory for Weld County oil and gas total point sources (61.8 Mg/yr).

- Samples collected at the BAO tall tower or while driving around the Front Range reflect the emissions from a complex mix of sources distributed over a large area. Using a multi-species analysis including both climate and air quality relevant gases, we can start unraveling the contributions of different source types. Daily multi-species measurements from the NOAA collaborative network of tall towers in the US provide a unique opportunity to understand source chemical signatures in different airsheds and how these emissions may change over time.
- More targeted multi-species well-calibrated atmospheric measurements are needed to evaluate current and future bottom-up inventory emissions calculations for the fossil fuel energy sector and to reduce uncertainties on absolute flux estimates for climate and air quality relevant trace gases.

Acknowledgements

The authors thank John Grant (ENVIRON) and Kathleen Sgamma (Western Energy Alliance) for their expertise and support in interpreting the WRAP Phase III inventory public data. Special thanks are extended to the NOAA personnel and collaborators responsible for flask preparation, sample collection and sample analysis, data quality control and database management.

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List of Figures

Figure 1: Map of the study area centered on the Boulder Atmospheric Observatory (BAO), located 25 km east-northeast of Boulder. Overlaid on this map are the locations of active oil and gas wells (light purple dots) as of April 2008 (data courtesy of SkyTruth, http://blog.skytruth.org/2008/06/colorado-all-natural-gas-and-oil-wells.html, based on COGCC well data). Also shown are the locations of landmarks used in the study, including selected point sources (NGP Plant = natural gas processing plant, WWT Plant = Lafayette wastewater treatment plant).

Figure 2: Observed median mixing ratios for several species measured in air samples taken at various sites at midday during June-August (2007-2010). The sites are described in Table 1. Only nighttime samples are shown for NWF to capture background air with predominantly down-slope winds. Notice the different units with all columns and the different scaling applied to methane, propane and n-butane.

Figure 3: Summertime and wintertime median mixing ratios of several species measured in air samples from the 300-meter level at the BAO tower for three wind sectors: North and East (NE) where the density of gas drilling operations is highest, South (S) with Denver 35 km away, and West (W) with mostly clean air. The time span of the data is from August 2007 to April 2010. Summer includes data from June to August and winter includes data from November to April. Due to the small number of data points (<15), we do not show summer values for the S and W wind sectors. Data outside of the 11am-3pm local time window were not used. Notice the different scales used for methane, propane and n-butane. The minimum number of data points used for each wind sector is: NE summer 33, NE winter 89, S winter 65 and W winter 111.

Figure 4: Correlation plots for various species measured in the BAO summertime NE wind sector flask samples (left column) and summer 2008 Mobile Lab (right column) samples. Data at BAO were filtered to keep only midday air samples collected between June and August over the time period spanning August 2007 to August 2009. See also Table 3.

Figure 5: (Top panel) Time series of the continuous methane measurements from Mobile Lab Survey # 9 on July 31, 2008. Also shown are the mixing ratio data for the 12 flask samples collected during the road survey. The GC/MS had a faulty high energy dynode cable when these samples were analyzed, resulting in more noisy data for the alkanes and the CFCs (σ < 10% instead of 5%). However, the amplitudes of the $C_{3\text{-}5}$ alkane signals are much larger than the noise here. The methane mixing ratio scale is shown on the left hand vertical axis. For all other alkanes, refer to the right hand vertical axis. (Bottom panel) Time series of wind directions at the NCAR Foothills and Mesa Laboratories in Boulder (see Figure 6 for locations) and from the 300-m level at the BAO on July 31, 2008.

Figure 6: Continuous methane observations (colored squares) and flask (circles) samples collected during the July 31, 2008 Mobile Lab Survey #9 in Boulder and Weld County. The size of the symbols (and the symbol color for the continuous methane data) represents the mixing ratio of continuous/flask methane (squares, green circles) and flask propane (blue circles). The labels indicate the flask sample number (also shown in the time series in Figure 5). NCAR = National Center for Atmospheric Research, FL = NCAR Foothills Laboratory, ML = NCAR Mesa Laboratory, WWT Plant = Lafayette wastewater treatment plant.

Figure 7: A) Propane versus methane mixing ratios for air samples collected during Survey #9 on July 31, 2008. B) n-butane versus propane mixing ratios in the same air samples. The black line in plot A shows the correlation line for samples not impacted by local sources of methane (all flasks except #4, 5, 8, and 12). The black line in plot B shows the correlation line for all samples except flask 12. The flask sample number is shown next to each data point. The twelve samples were filled sequentially (see Figure 6).

Figure 8: A) Propane versus methane mixing ratios for air samples collected during Survey #6 on July 14, 2008. B) n-butane versus propane mixing ratios in the same air samples. The black line in plot A shows the correlation line for samples not impacted by local sources of methane (all flasks except 1-3, 5, and 9). The black line in plot B shows the correlation line for samples not impacted by local sources of propane.

Figure 9: Alkane correlation slopes in air samples collected at BAO (NE wind sector, summer samples only, blue) and over the Denver-Julesburg Basin (red) during the Front Range Study (June-July 2008) are compared with VOC emissions molar ratios for flashing (green) and venting (grey) sources used by Bar-Ilan et al. [2008a] for the DJB WRAP Phase III emissions inventory. The error bars indicate the min and max values for the flashing emissions molar ratios. Also shown are the mean, min and max molar ratios derived from the composition analysis of gas samples collected in 2006 at 77 different gas wells in the Great Wattenberg Area (yellow, [Colorado Oil and Gas Conservation Commission, 2007]). Goldan et al. [1995] data are from a two week measurement campaign in the Foothills, west of Boulder, in February 1991 (light purple). Goldan et al. identified a "local" propane source (lower limit for correlation slope) with clear C_{4-5} alkane ratios to propane (dark propane, see also text). The error bars on the observed atmospheric molar ratios are the 2-sigma calculated for the ratios with linmix_err.pro (http://idlastro.gsfc.nasa.gov/ftp/pro/math/linmix_err.pro).

Figure 10: Bottom-up (inventory-derived) emission estimates and top-down emission scenarios for CH_4, C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12} and C_6H_6 in Weld County. The vertical bars show scenario 1 average values and the error bars indicate the minimum and maximum values for the three scenarios described in Table 4.

Tables

Table 1: Locations of a subset of the NOAA ESRL Towers and Aircraft Profile Sites used in this study. STR and WGC in Northern California are collaborations with Department of Energy Environmental Energy Technologies Division at Lawrence Berkeley National Laboratory (PI: Marc Fischer). The last column gives the altitudes of the quasi-daily flask air samples used in this study. We use midday data for all sites, but at Niwot Ridge Forest we used night time data to capture background air from summertime downslope flow. We also show the location information of SGP, a NOAA ESRL aircraft site in north central Oklahoma, for which we used samples taken below 650 meters altitude.

Site Code	City	State	Latitude ^{o}North	Longitude ^{o}East	Elevation (meters above sea level)	Sampling Height (meters above ground)
BAO	Erie	Colorado	40.05	105.01	1584	300
LEF	Park Falls	Wisconsin	45.93	90.27	472	396
NWF	Niwot Ridge	Colorado	40.03	105.55	3050	23
STR	San Francisco	California	37.7553	122.45	254	232
WGC	Walnut Grove	California	38.265	121.49	0	91
WKT	Moody	Texas	31.32	97.33	251	457
SGP*	Southern Great Plains	Oklahoma	36.80	97.50	314	< 650

* aircraft discrete air samples

Table 2: List of the Front Range Mobile Lab measurement and flasks sampling surveys. Some trips (#1, 2, 3, 4, 6) sampled air using the flask only. Surveys # 5 and 7 used only the continuous analyzers on the Mobile Lab with no discrete flask collection. The last two trips targeted flask sampling close to known point or area sources based on the continuous methane measurement display in the Mobile Lab.

Road Survey #	Road Survey Date	Geographical Area / Target sources	Measurements/ Sampling Technique
1	**June 4**	Boulder	12 flasks
2	**June 11**	Boulder + Foothills	12 flasks
3	**June 19**	NOAA-Longmont-Fort Collins-Greeley (Oil and Gas Drilling, Feedlots)	24 flasks
4	**July 1**	NOAA - Denver	12 flasks
5	**July 9**	Around Denver	Picarro
6	**July 14**	NOAA - Greeley	12 flasks
7	**July 15**	NOAA-Greeley	Picarro
8	**July 25**	BAO surroundings Dacono Natural Gas Compressor - Feedlot	Picarro + 8 flasks
9	**July 31**	"Regional" CH_4 enhancements, Landfill, Corn field	Picarro + 12 flasks

Table 3: Correlation slopes and r^2 for various species measured in the BAO tower midday air flask samples for summer (June to August, when more than 25 samples exist) and winter (November to April) over the time period spanning August 2007 to April 2010. The three wind sectors used in Figure 3 are also used here with a 30-min average wind speed threshold of 2.5 m/s. Also shown are the slopes derived from flask samples collected by the Mobile Lab in summer 2008. The slope is in bold when r^2 is higher than 0.7 and the slope is not shown when r^2 is less than 0.4. The number of data points (n) used for the slope and r^2 calculations are provided. All slope units are ppb/ppb, except for C_6H_6/C_3H_8, C_6H_6/CO and C_2H_2/CO, which are in ppt/ppb. We used the IDL routine linmix_err.pro for the calculations with the following random measurement errors: 2ppb for CH_4 and CO and 5% for C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12}, C_2H_2, and C_6H_6.

Sector		**BAO North and East**						**BAO South**			**BAO West**			**Mobile Lab**		
Season		**summer**			**winter**			**winter**			**winter**			**summer**		
Molar ratios y/x	**units**	**slope**	r^2	n	**slope**	r^2	n	**slope**	r^2	n	**slope**	r^2	n	**slope**	r^2	n
C_3H_8/ CH_4	ppb/ ppb	**0.104 ±0.005**	0.85	81	**0.105 ±0.004**	0.90	115	0.079 ±0.008	0.53	130	**0.085 ±0.005**	0.73	148	**0.095 ±0.007**	0.76	77
nC_4H_{10}/ C_3H_8	ppb/ ppb	**0.447 ±0.013**	1.00	81	**0.435 ±0.005**	1.0	120	**0.449 ±0.011**	0.98	131	**0.434 ±0.006**	1.00	151	**0.490 ±0.011**	1.00	85
iC_5H_{12}/ C_3H_8	ppb/ ppb	**0.14 1 ±0.004**	1.00	81	**0.134 ±0.004**	0.98	120	**0.142 ±0.009**	0.81	121	**0.130 ±0.004**	0.94	151	**0.185 ±0.011**	0.81	85
nC_5H_{12}/ C_3H_8	ppb/ ppb	**0.150 ±0.003**	1.00	81	**0.136 ±0.004**	0.98	120	**0.142 ±0.006**	0.90	131	**0.133 ±0.003**	0.91	151	**0.186 ±0.008**	0.92	85
C_6H_6/ C_3H_8	ppt/ ppb	10.1 ±1.2	0.67	49	**8.2 ±0.5**	0.79	117	-	0.33	130	-	0.39	150	**17.9 ±1.1**	0.95	46
C_6H_6/ CO	ppt/ ppb	2.89 ±0.40	0.58	53	3.18 ±0.24	0.69	112	**1.57 ±0.08**	0.85	123	**1.81 ±0.08**	0.83	148	**1.82 ±0.12**	0.89	39
C_2H_2/ CO	ppt/ ppb	**3.15 ±0.33**	0.85	81	**7.51 ±0.39**	0.85	100	**5.03 ±0.17**	0.92	110	**5.85 ±0.25**	0.86	131	**4.32 ±0.28**	0.89	39
C_6H_6/ C_2H_2	ppt/ ppt	0.51 ±0.09	0.55	50	**0.34 ±0.02**	0.90	103	**0.27 ±0.02**	0.90	111	**0.32 ±0.02**	0.96	132	**0.37 ±0.04**	0.75	39

Table 4: Bottom-up (inventory-derived) emission estimates and top-down emissions scenarios for CH_4 and C_3H_8 in Weld County.

	Bottom-Up Estimates				**Top-Down Scenarios[e]: Venting**			**Top-Down Scenarios[e]: TOTAL Bottom-Up Flashing + Top-Down Venting**			**Top-Down Scenarios[e]: % of production vented[f]**		
Gg/yr	**Flashing[b]**	**Venting[c]**	**Flashing + venting**	**% of production vented[d]**	**1**	**2**	**3**	**1**	**2**	**3**	**1**	**2**	**3**
methane	**11.2**	53.1	64.3	**1.68%**	118.4	92.5	157	**129.6**	103.7	168.2	**4.0%**	3.1%	5.3%
min[a]	**4**	42	46		86.5	67.6	114.7	90.5	**71.6**	118.7	2.9%	**2.3%**	3.8%
max[a]	**23**	63	86		172.6	134.9	228.9	195.6	157.9	**251.9**	5.8%	4.5%	**7.7%**
propane	**18.3**	7.8	26.1		17.4	10.2	28	**35.7**	28.5	46.3			
min[a]	**14**	1	15		12.7	7.5	20.5	26.7	**21.5**	34.5			
max[a]	**24**	28	52		25.3	14.9	40.8	49.3	38.9	**64.8**			

[a] The minimum and maximum values reported here come from the ensemble of 16 condensate tank emissions speciation profiles provided by CDPHE.

[b] The bottom-up flashing emissions for methane and propane were calculated using the 2008 estimate of total VOC flash emissions derived by averaging the WRAP estimate for 2006 and the projection for 2010 (Cf. section 4.3).

[c] The bottom-up venting emissions for methane and propane were calculated using the WRAP Phase III inventory estimate for the total volume of natural gas vented and the GWA 77 natural gas composition profiles.

[d] Using the WRAP Phase III inventory data set and assumptions, including a CH_4 mean molar ratio of 77.44% for the vented natural gas and a molar volume for the gas of 22.4 L/mol.

[e] The CH_4-to-C_3H_8 molar ratio for vented natural gas is 18.75 (WRAP report estimate) for scenario 1, 15.43 for scenario 2 (median of molar ratios in GWA data set) and 24.83 for scenario 3 (mean of molar ratios in GWA data set).

[f] Using the assumptions of a CH_4 molar ratio of 77% for the vented natural gas and a molar volume for the gas of 23.6 L/mol (Pressure= 14.73 pounds per square inch and Temperature= 60^{o}F) as used by the EIA [EIA, 2004].

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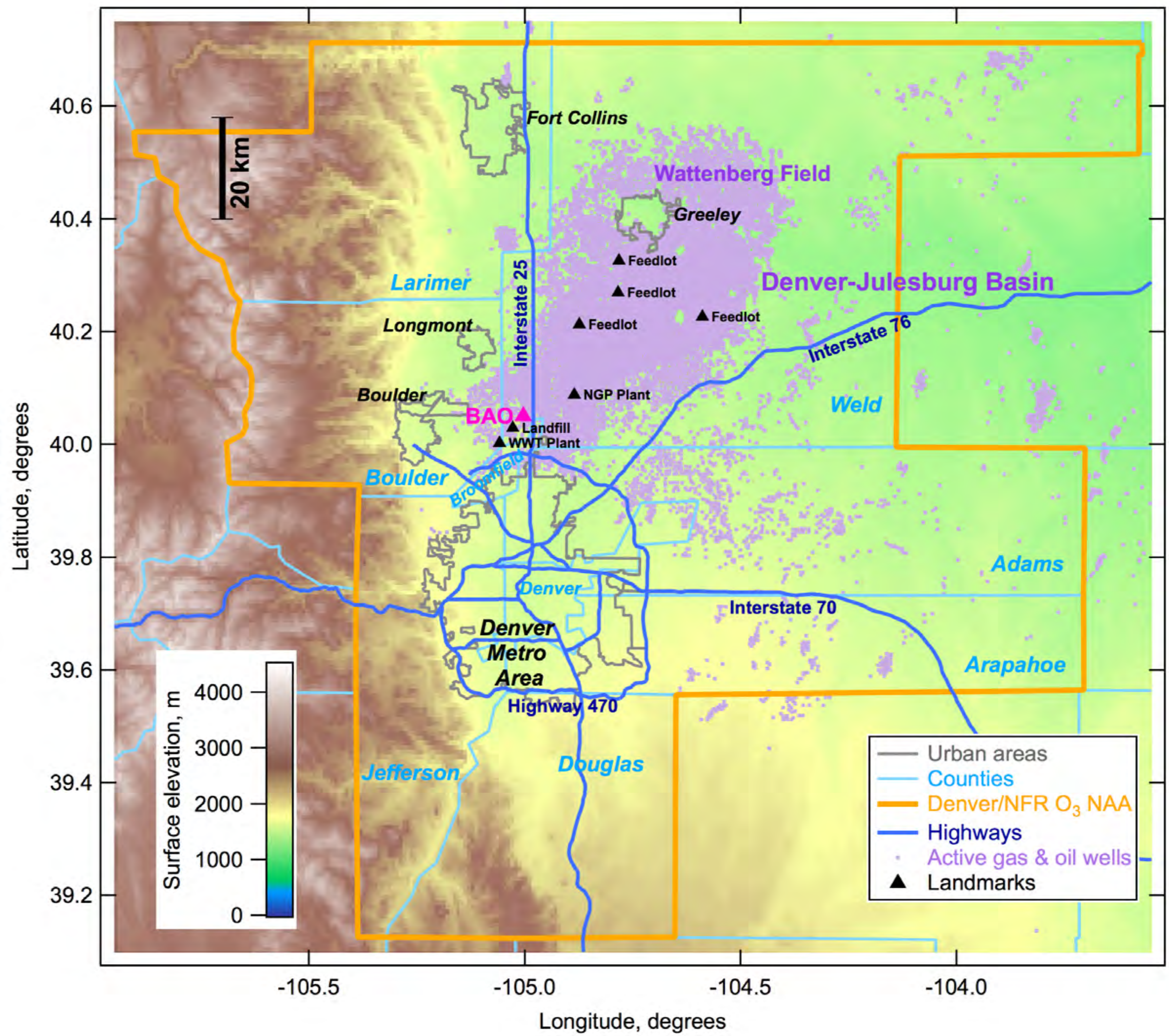

Fort Collins
Wattenberg Field
Greeley
Feedlot
Feedlot
Feedlot
Feedlot
Denver-Julesburg Basin
Larimer
Interstate 25
Longmont
Interstate 76
NGP Plant
Boulder
BAO
Landfill
WWT Plant
Weld
Boulder
Broomfield
Adams
Denver
Interstate 70
Denver Metro Area
Arapahoe
Highway 470
Jefferson
Douglas
20 km
Surface elevation, m
4000
3000
2000
1000
0
Urban areas
Counties
Denver/NFR O_3 NAA
Highways
Active gas & oil wells
Landmarks
Latitude, degrees
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40.4
40.2
40.0
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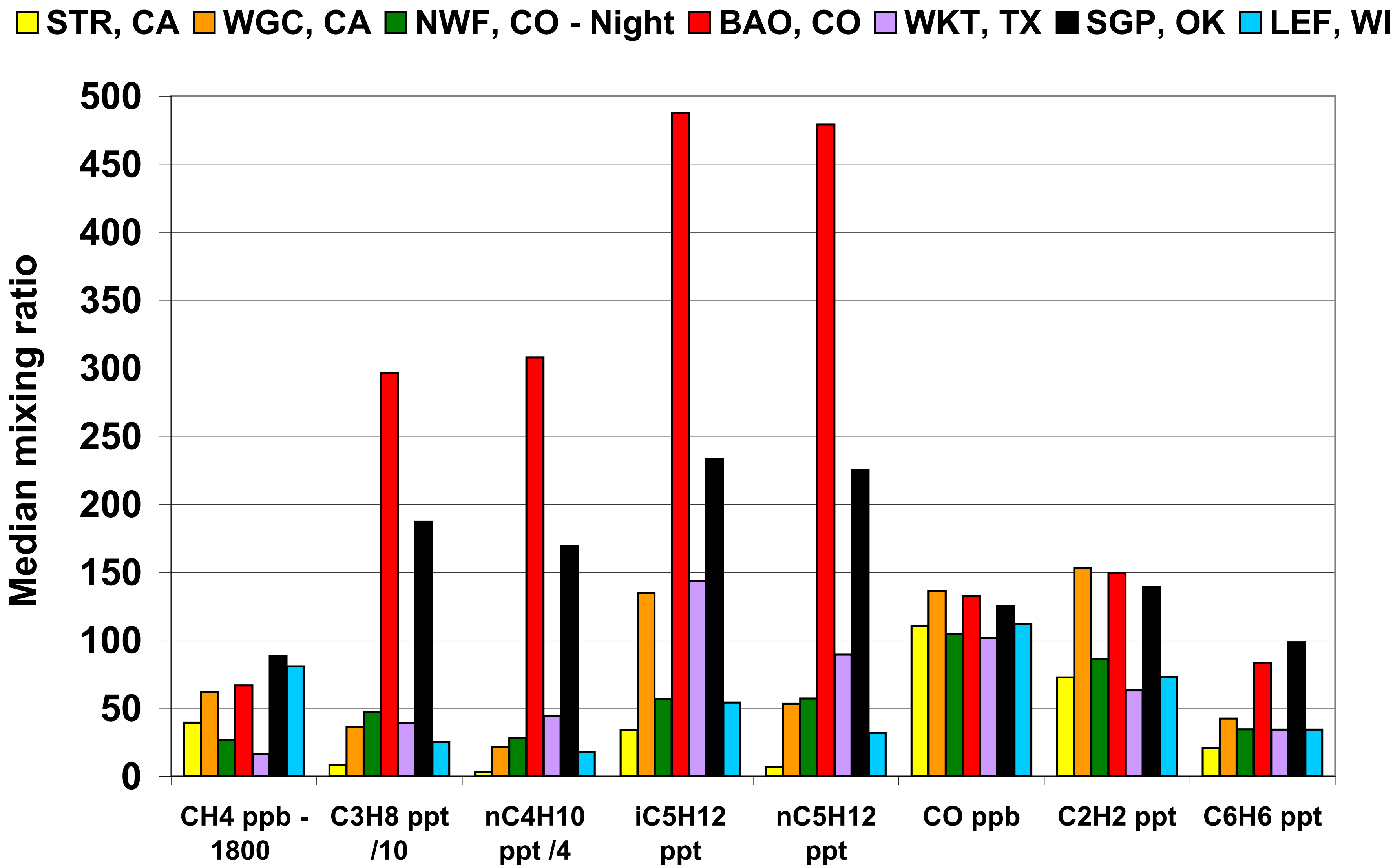
-104.5
-104.0
Longitude, degrees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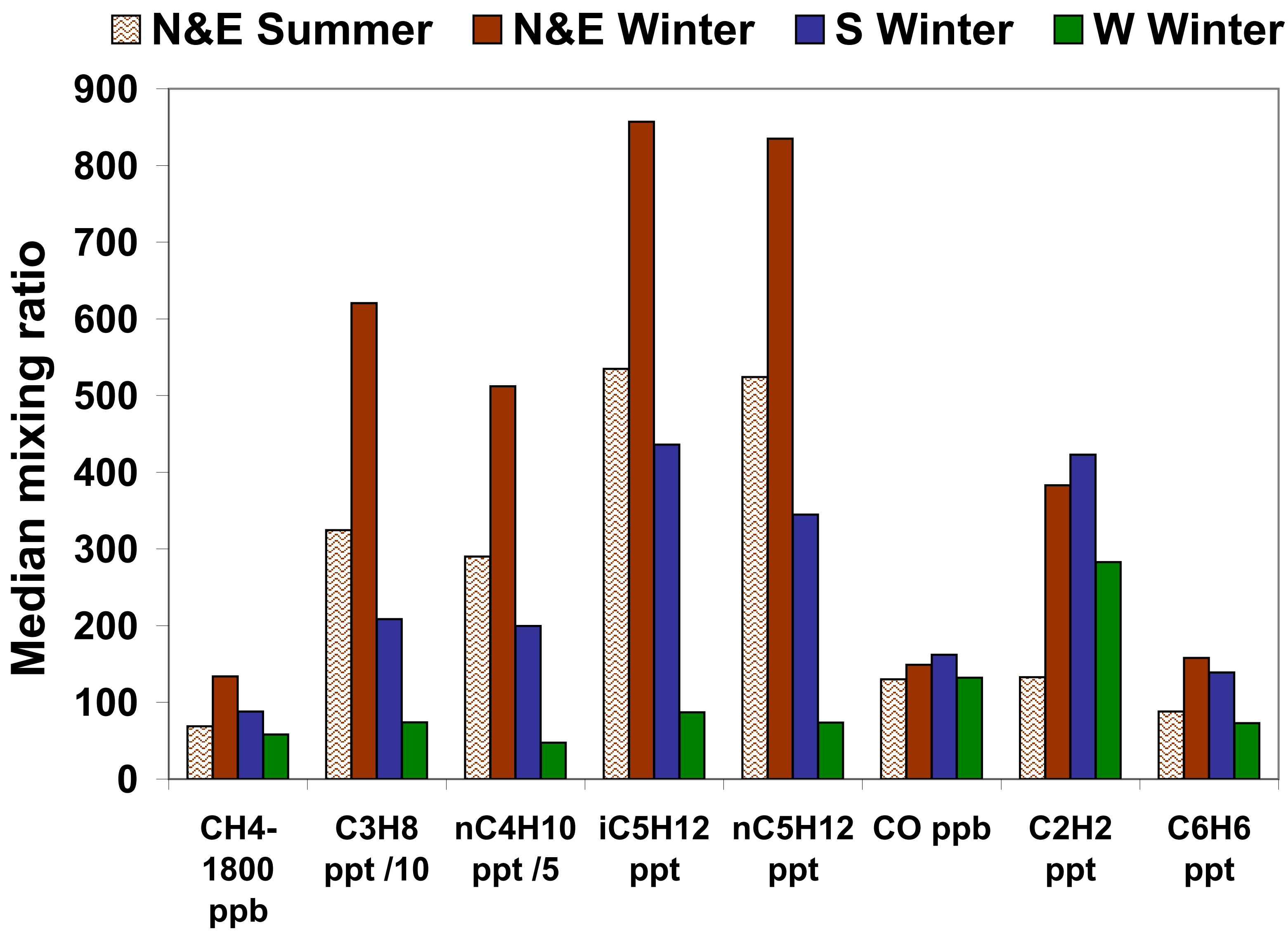
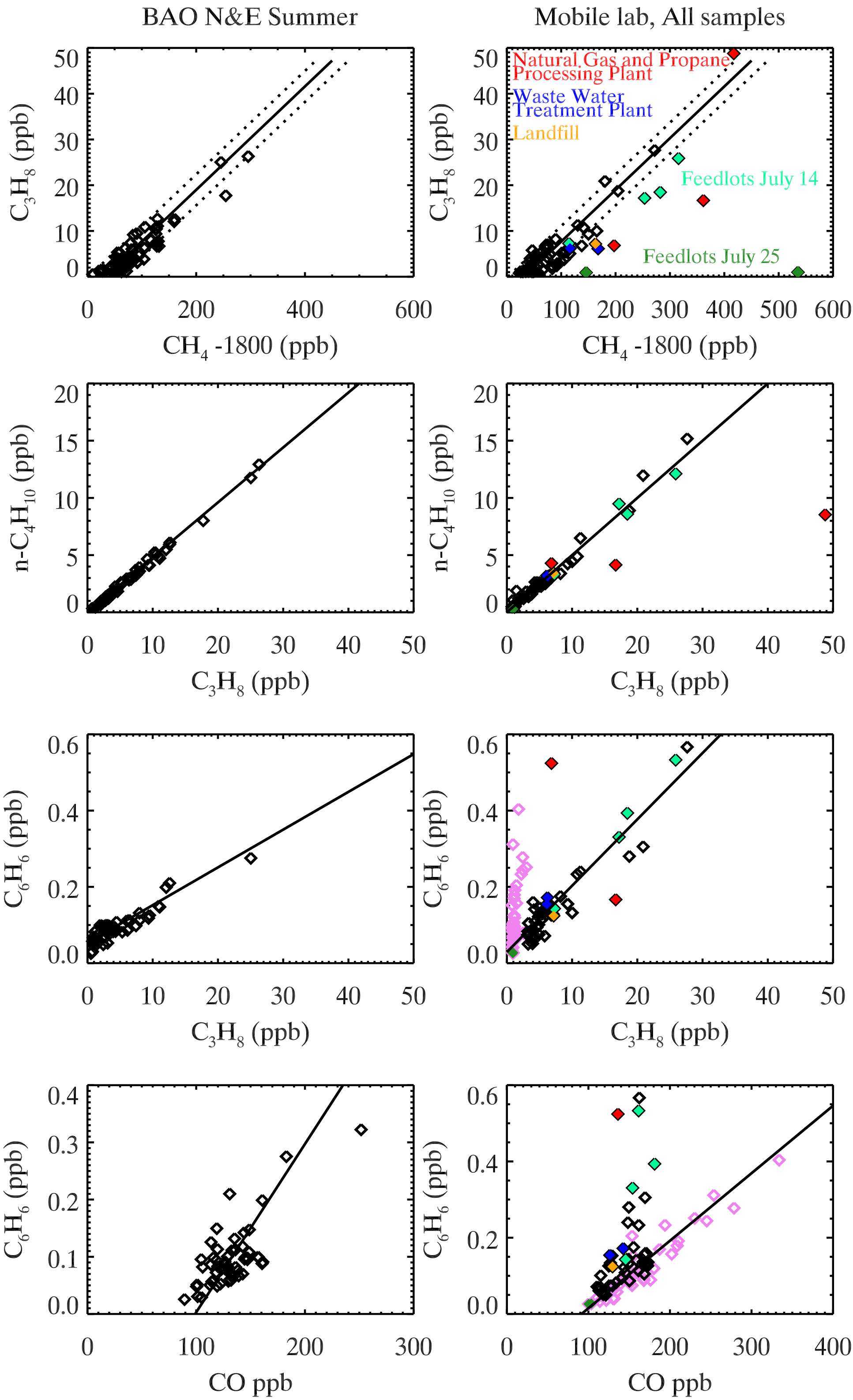
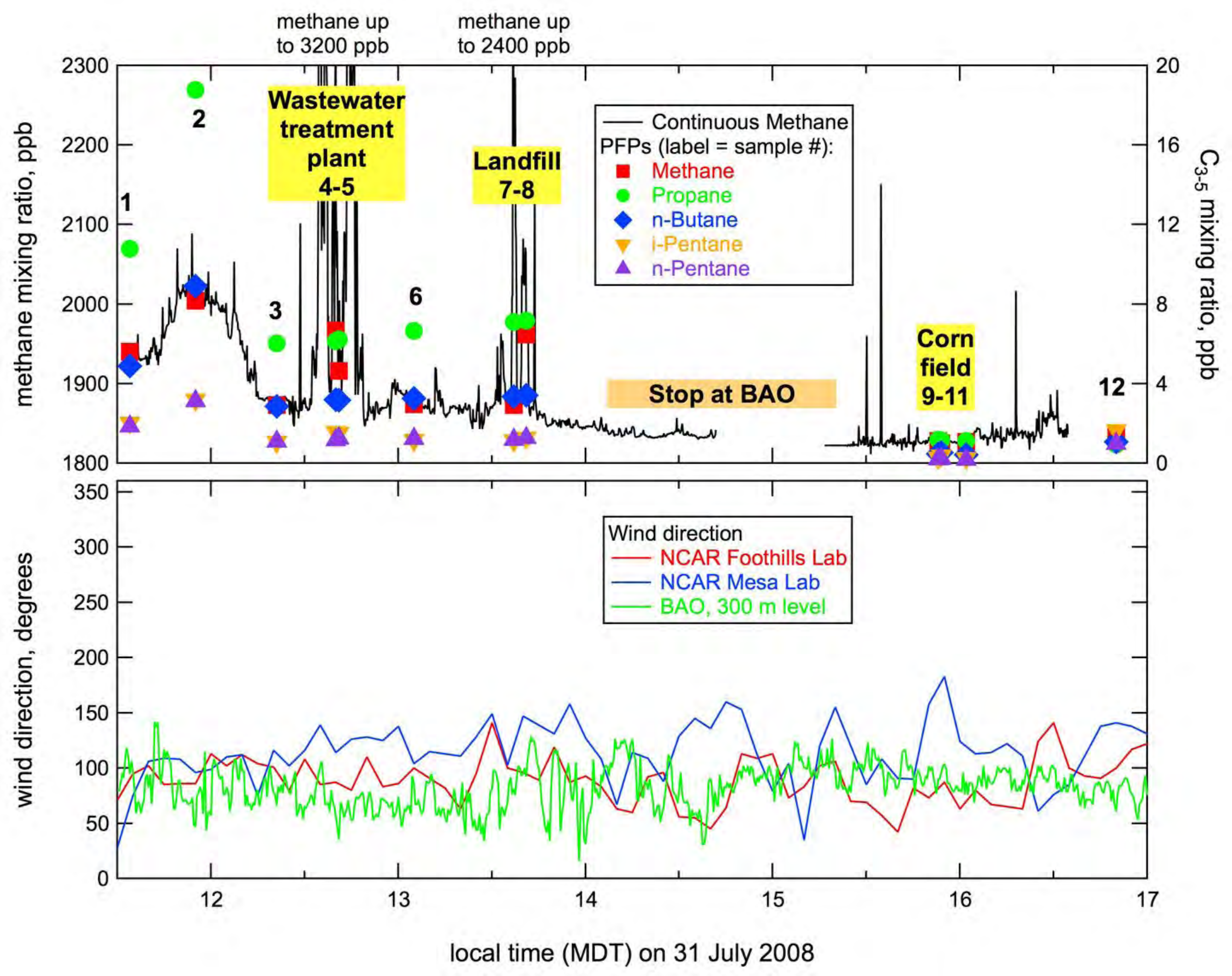
WGC, CA
NWF, CO - Night
BAO, CO
WKT, TX
SGP, OK
LEF, WI
Median mixing ratio
500
450
400
350
300
250
200
150
100
50
0
CH4 ppb - 1800
C3H8 ppt /10
nC4H10 ppt /4
iC5H12 ppt
nC5H12 ppt
CO ppb
C2H2 ppt
C6H6 ppt

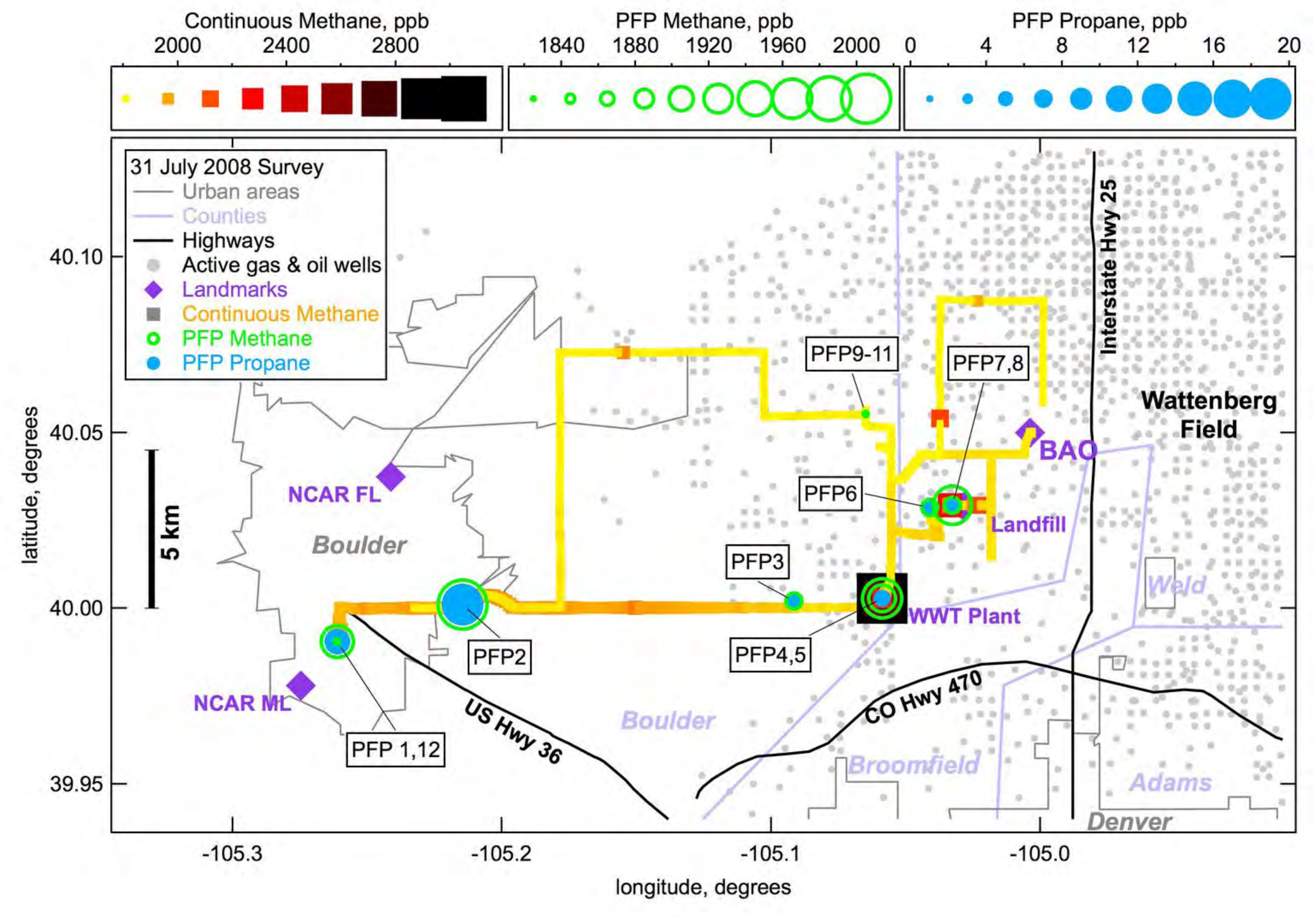


N&E Summer
N&E Winter
S Winter
W Winter
Median mixing ratio
900
800
700
600
500
400
300
200
100
0
CH4-1800 ppb
C3H8 ppt /10
nC4H10 ppt /5
iC5H12 ppt
nC5H12 ppt
CO ppb
C2H2 ppt
C6H6 ppt

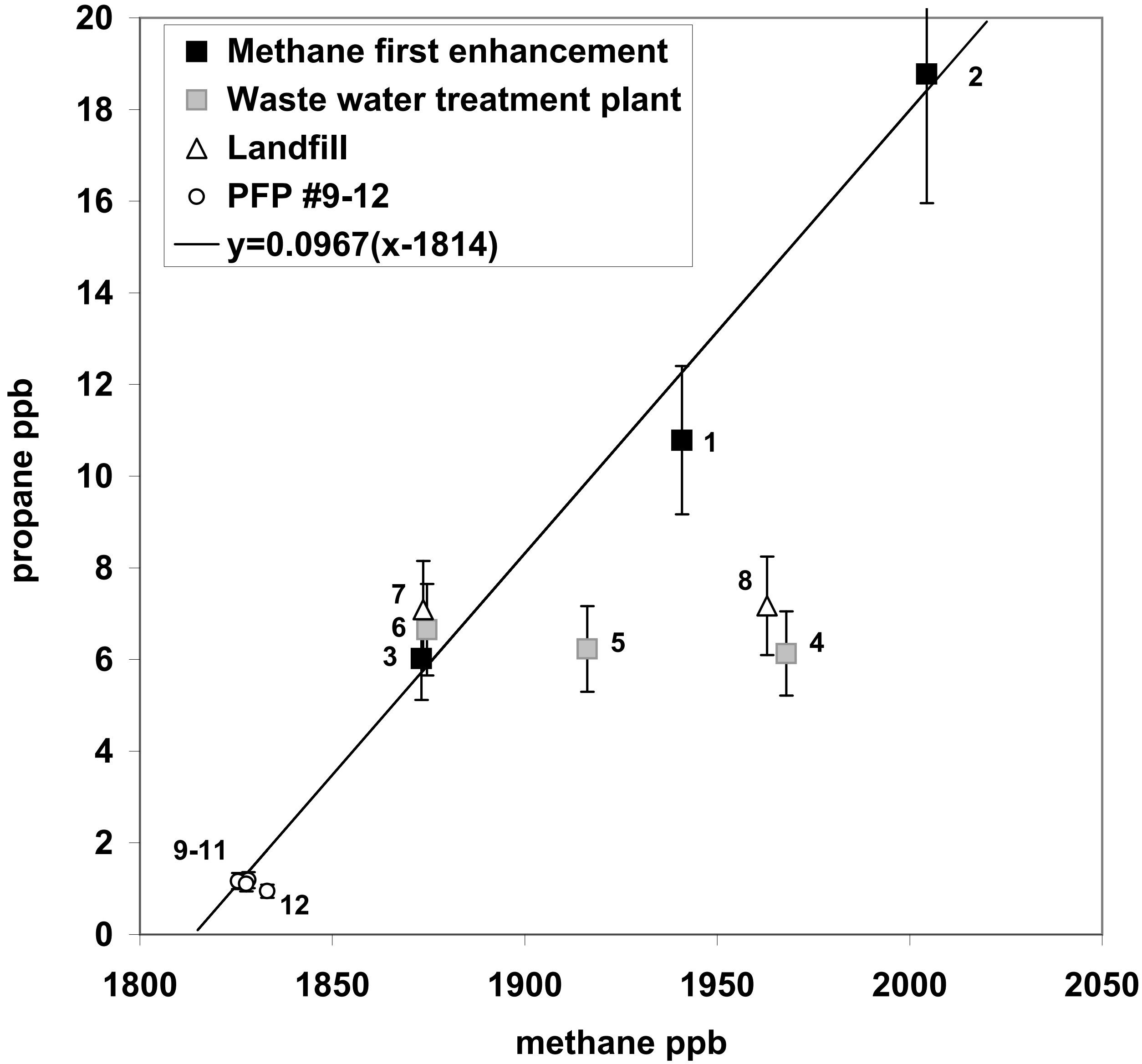


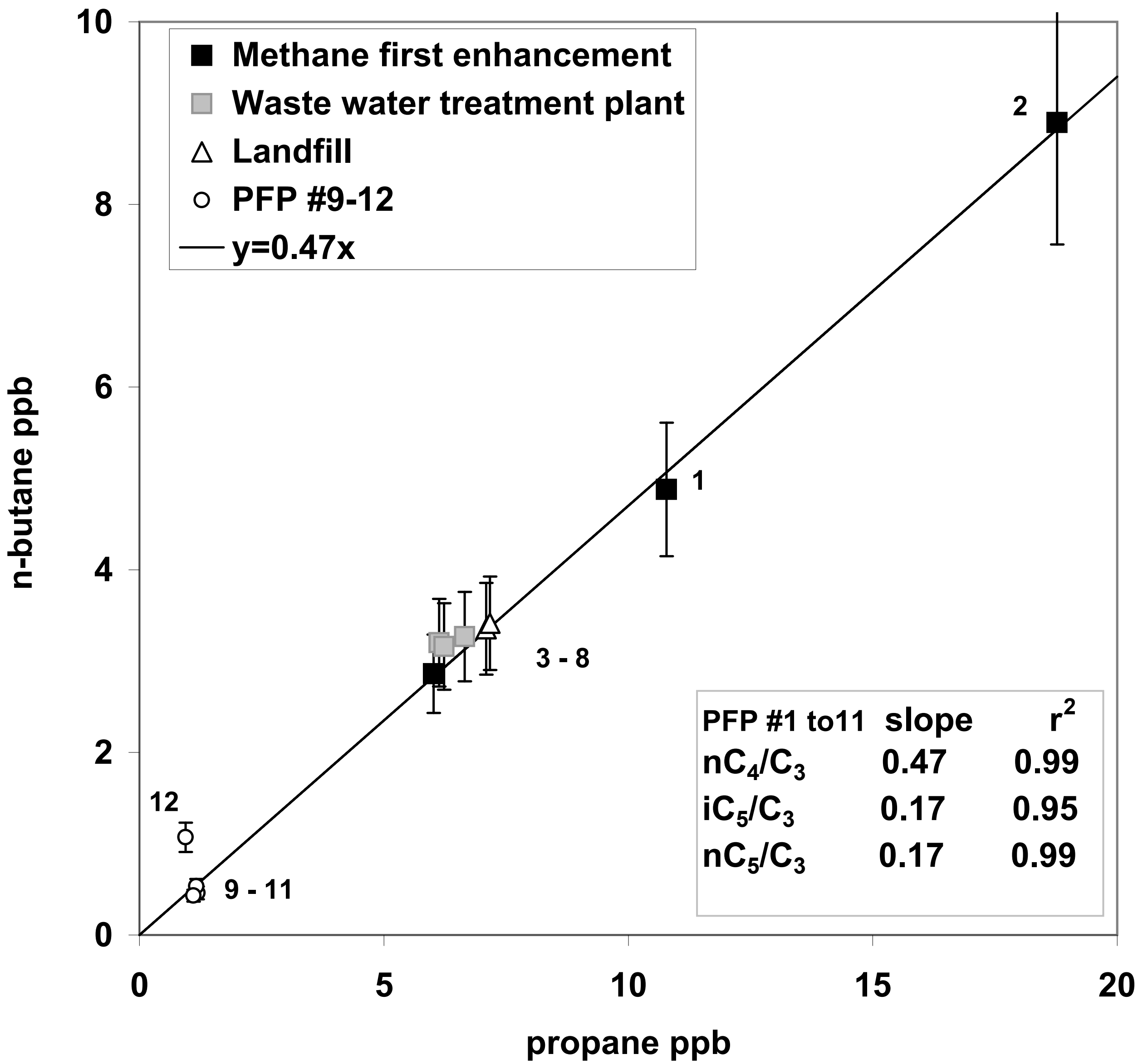
BAO N&E Summer
Mobile lab, All samples
C3H8 (ppb)
CH4 -1800 (ppb)
Natural Gas and Propane
Processing Plant
Waste Water
Treatment Plant
Landfill
Feedlots July 14
Feedlots July 25
n-C4H10 (ppb)
C3H8 (ppb)
C6H6 (ppb)
CO ppb


methane up
to 3200 ppb
methane up
to 2400 ppb
Wastewater
treatment
plant
4-5
Landfill
7-8
Continuous Methane
PFPs (label = sample #):
Methane
Propane
n-Butane
i-Pentane
n-Pentane
1
2
3
6
12
Stop at BAO
Corn
field
9-11
methane mixing ratio, ppb
C3-5 mixing ratio, ppb
Wind direction
NCAR Foothills Lab
NCAR Mesa Lab
BAO, 300 m level
wind direction, degrees
local time (MDT) on 31 July 2008

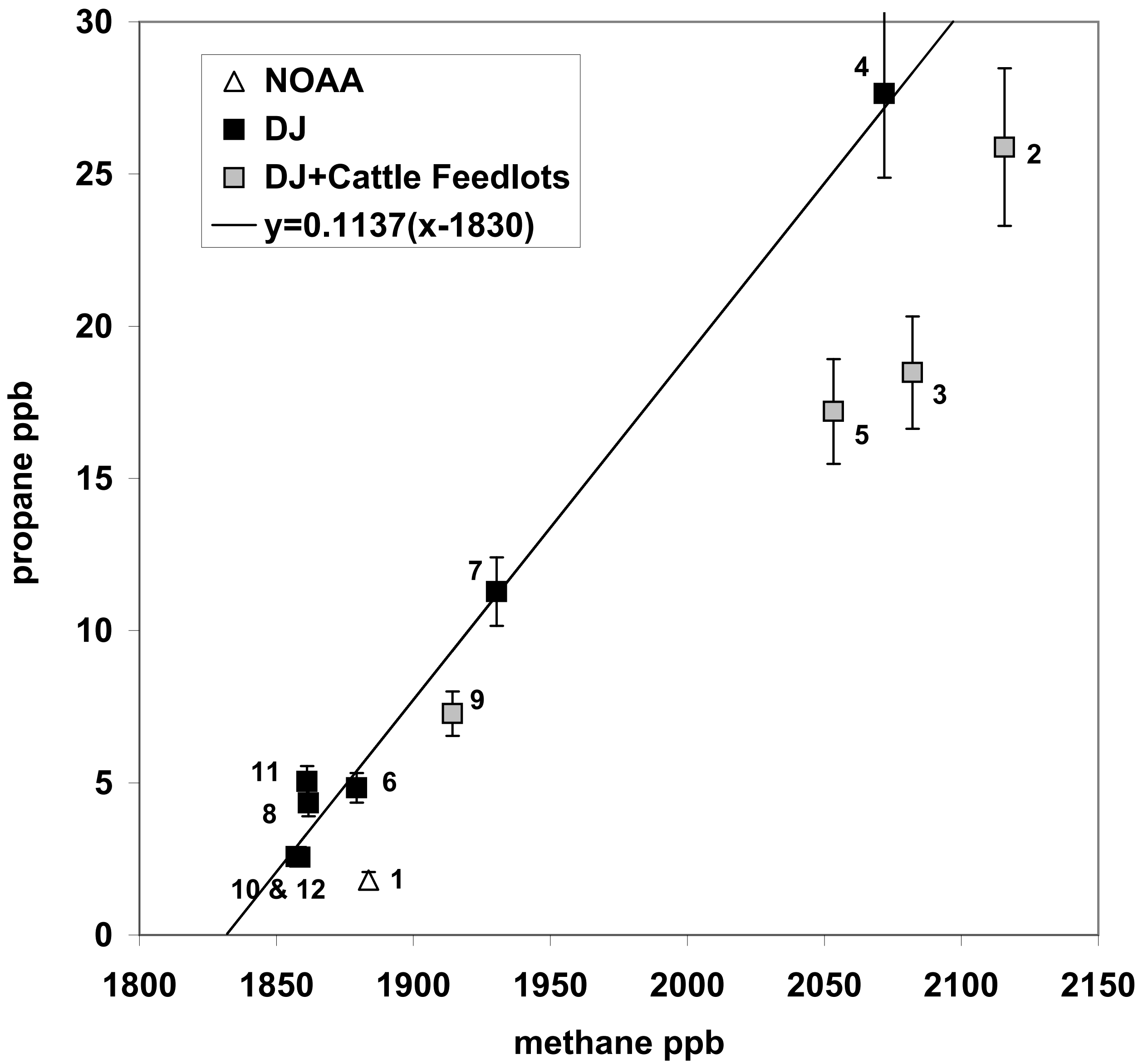


Continuous Methane, ppb
2000
2400
2800
PFP Methane, ppb
1840
1880
1920
1960
2000
PFP Propane, ppb
0
4
8
12
16
20
31 July 2008 Survey
Urban areas
Counties
Highways
Active gas & oil wells
Landmarks
Continuous Methane
PFP Methane
PFP Propane
Interstate Hwy 25
Wattenberg Field
PFP9-11
PFP7,8
BAO
PFP6
Landfill
NCAR FL
Boulder
5 km
PFP3
WWT Plant
PFP4,5
PFP2
PFP 1,12
NCAR ML
US Hwy 36
CO Hwy 470
Boulder
Broomfield
Weld
Adams
Denver
40.10
40.05
40.00
39.95
latitude, degrees
-105.3
-105.2
-105.1
-105.0
longitude, degrees

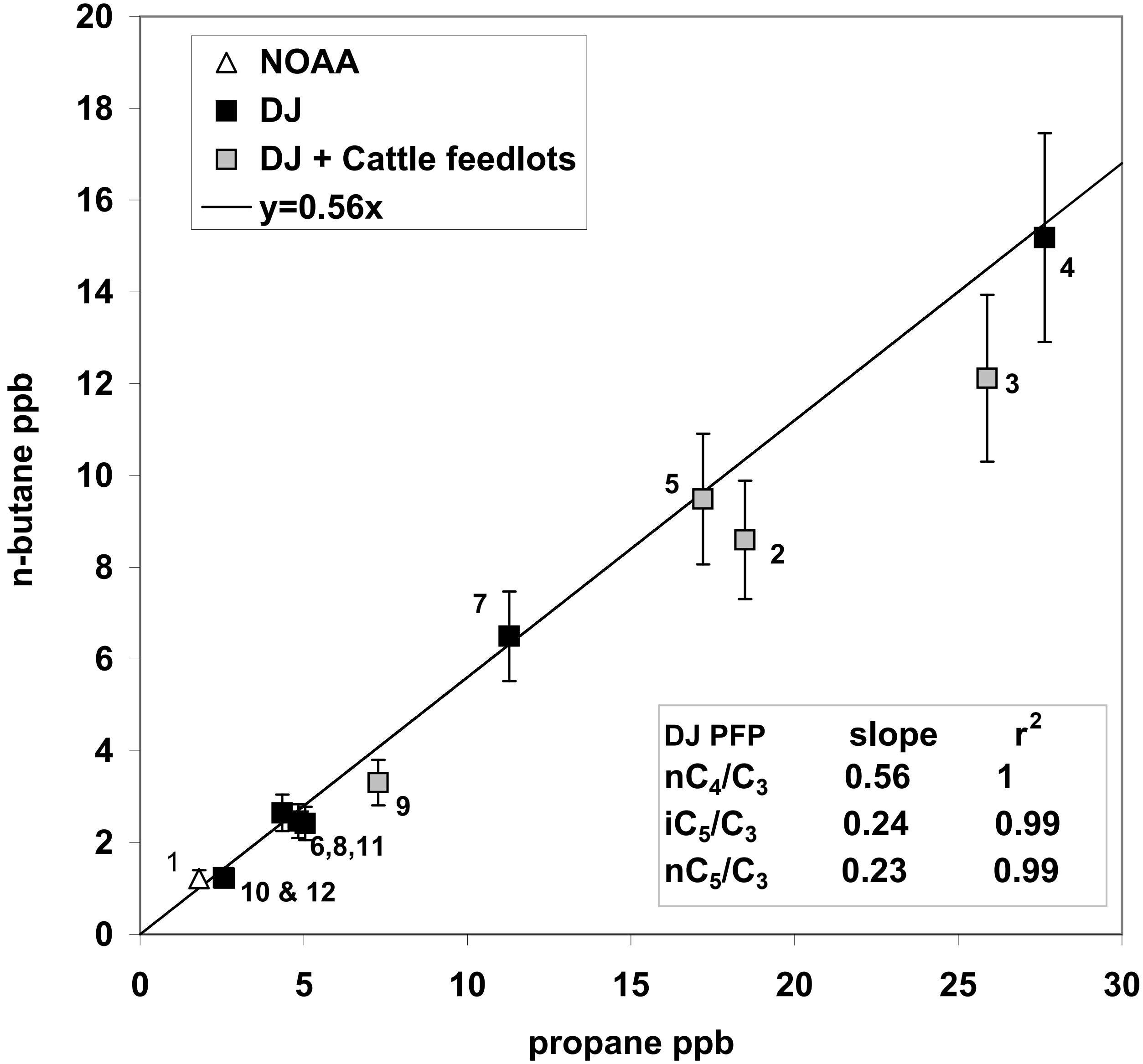

Methane first enhancement
Waste water treatment plant
Landfill
PFP #9-12
y=0.0967(x-1814)
propane ppb
methane ppb
0
2
4
6
8
10
12
14
16
18
20
1800
1850
1900
1950
2000
2050
1
2
3
4
5
6
7
8
9-11
12



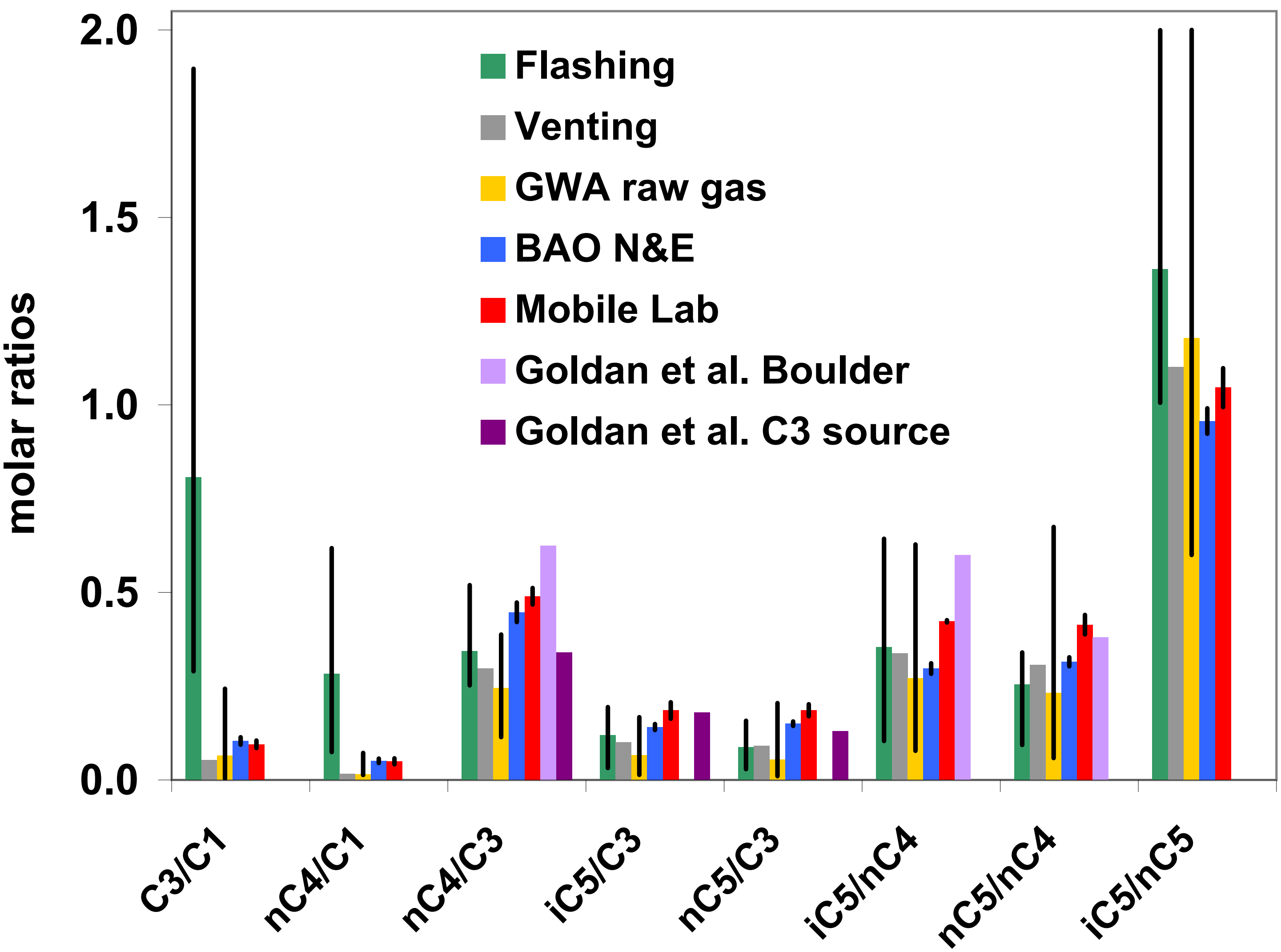
Methane first enhancement
Waste water treatment plant
Landfill
PFP #9-12
y=0.47x
2
1
3 - 8
12
9 - 11
PFP #1 to11 slope r2
nC4/C3 0.47 0.99
iC5/C3 0.17 0.95
nC5/C3 0.17 0.99
n-butane ppb
propane ppb
0
2
4
6
8
10
0
5
10
15
20



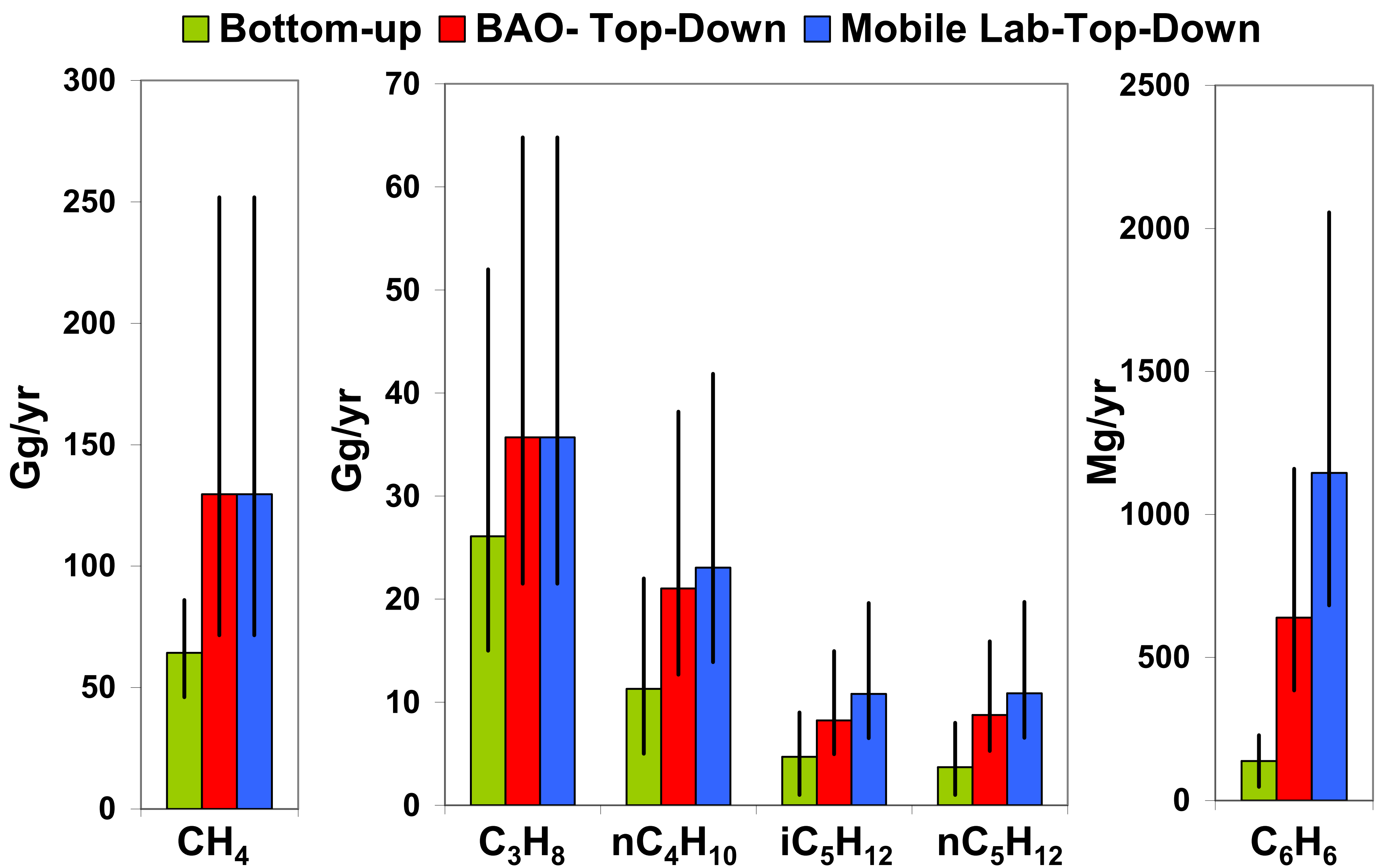
NOAA
DJ
DJ+Cattle Feedlots
y=0.1137(x-1830)
propane ppb
methane ppb
0
5
10
15
20
25
30
1800
1850
1900
1950
2000
2050
2100
2150
1
2
3
4
5
6
7
8
9
10 & 12
11



NOAA
DJ
DJ + Cattle feedlots
y=0.56x
n-butane ppb
propane ppb
1
10 & 12
6,8,11
9
7
5
2
3
4
DJ PFP slope r^2
nC_4/C_3 0.56 1
iC_5/C_3 0.24 0.99
nC_5/C_3 0.23 0.99



molar ratios
2.0
1.5
1.0
0.5
0.0
Flashing
Venting
GWA raw gas
BAO N&E
Mobile Lab
Goldan et al. Boulder
Goldan et al. C3 source
C3/C1
nC4/C1
nC4/C3
iC5/C3
nC5/C3
iC5/nC4
nC5/nC4
iC5/nC5


Bottom-up
BAO- Top-Down
Mobile Lab-Top-Down
Gg/yr
300
250
200
150
100
50
0
CH_4
Gg/yr
70
60
50
40
30
20
10
0
C_3H_8
nC_4H_{10}
iC_5H_{12}
nC_5H_{12}
Mg/yr
2500
2000
1500
1000
500
0
C_6H_6

Supplementary Tables

Table 1S: Methane source estimates in Colorado (Gg CH4 /yr, for 2005)

Table 2S: Natural gas and crude oil production in Weld County, Colorado, and the US for 2005 and 2008 (Bcf=Billion cubic feet)

Table 3S: Total VOC and benzene source estimates for Weld County in different bottom-up inventories. Source categories may not sum to total due to rounding.
Sources: WRAP for year 2006 [Bar Ilan et al., 2008a], CDPHE for 2008 [CDPHE, personal communication], NEI 2005 [EPA, 2008], NEI 2008 [EPA, 2011b]

Table 4S: Inventory and measurement derived molar ratios for the various data sets plotted on Figure 9. Flashing emissions composition is based on EPA TANK model runs for 16 condensate tanks located in the DJB and sampled in 2002 [CDPHE, personal communication 2010]. Venting emissions composition is based on an average raw gas weight composition profile provided by Bar-Ilan et al. [2008a] and derived private data from several natural gas producing companies in the DJB. To get a range of distribution for vented emissions, we use the molar composition provided by COGCC for raw gas samples collected at 77 wells in the DJB in December 2006. The BAO NE summer data and Mobile Lab data are the same as in Table 3. The Goldan et al. data for samples collected west of Boulder in February 1991 are based on Goldan et al. [1995] Table 1 and Figure 5.

Supplementary Figures

Figure 1S: Time series of the Boulder Atmospheric Observatory flask data (collected between 17 and 21 UTC).

Figure 2S: Denver - Northern Front Range NAA VOC emissions inventories for oil and gas exploration, production and processing operations, developed by Bar-Ilan et al. [2008a,b]. The 2006 inventory is based on reported emissions for large condensate tanks and other permitted source categories identified with a (*) in the legend. Other source estimates are based on activity data and emissions factors. The 2010 ?projection? inventory was extrapolated based on oil and gas production trends, the 2006 emissions data, and federal and state regulations for emissions control of permitted sources that were ?on the book as of early 2008?. We distinguish three types of emissions based on distinct VOC speciation profiles used in the WRAP inventory: (1) flashing emissions from small and large condensate tanks; (2) venting emissions associated with leaks of raw natural gas at the well site or in the gathering network of pipelines; and (3) other emissions such as compressor engines (3% of total source), truck loading of condensate (1%), heaters, drill rigs, workover rigs, exempt engines, and spills which have different VOC emissions profiles.

Figure 3S: PFP samples collected during the mobile survey on July 14, 2008. The size of the symbols indicates the mixing ratio of PFP methane (red circles) and propane (green circles). The labels indicate the PFP sample number. NGP Plant = natural gas processing plant, WWT = Lafayette wastewater treatment plant.

Figure 4S: Molar composition of the venting (grey) and flashing (green) emissions data used to construct the bottom-up VOC emissions inventory for the DJB (average venting profile shared by Bar-Ilan et al. [2008a], flashing emissions profile based on EPA TANK runs for 16 condensate tanks in the DJB [CDPHE, personal communication]). For flashing emissions we show the average (green bar) and the minimum and maximum (error bars) molar fractions for all species. Also shown are the average (yellow bars) and the minimum and maximum molar fractions (error bars) of the various alkanes derived from the COGCC raw gas composition data for 77 wells in the Greater Wattenberg Area (GWA) (no aromatics data for this data set).

Figure 5S: Flow diagram of the calculation of speciated bottom-up emission estimates.

Figure 6S: Bottom-up flashing and venting emission estimates for Weld County in 2008. The colored bars indicate the mean emission estimates while the error bars indicate the minimum and maximum estimates. The WRAP inventory for the DJB used only one vented gas profile and therefore the corresponding Venting-WRAP emission estimates do not have error bars.

Table 1S: Methane source estimates in Colorado (Gg CH_4 /yr, for 2005)
Source: Strait et al., 2007

Natural gas systems	238
Coal mining	233
Enteric fermentation	143
Landfills	71
Manure management	48
Waste water treatment plants	24
Petroleum systems	10
Colorado total	767

Table 2S: Natural gas and crude oil production in Weld County, Colorado, and the US for 2005 and 2008 (Bcf=Billion cubic feet)

Source: COGCC (Weld County) and EIA (Colorado and US)

Year	**2005**			**2008**		
Gross withdrawal/ production	Natural gas *Bcf/yr*	Crude oil *Million barrels/yr*	Lease condensate *Million barrels/yr*	Natural gas *Bcf/yr*	Crude oil *Million barrels/yr*	Lease condensate *Million barrels/yr*
Weld County (% of Colorado)	188.5 (16.5%)	11.7 (51.3%)	na	202.1 (15.3%)	17.3 (71.8%)	na
DNFR NAA	201.1	12.6	na	214.1	18.5	na
Colorado	1144	22.8	5	1403	24.1	7
USA	23457	1890.1	174	25636	1811.8	173

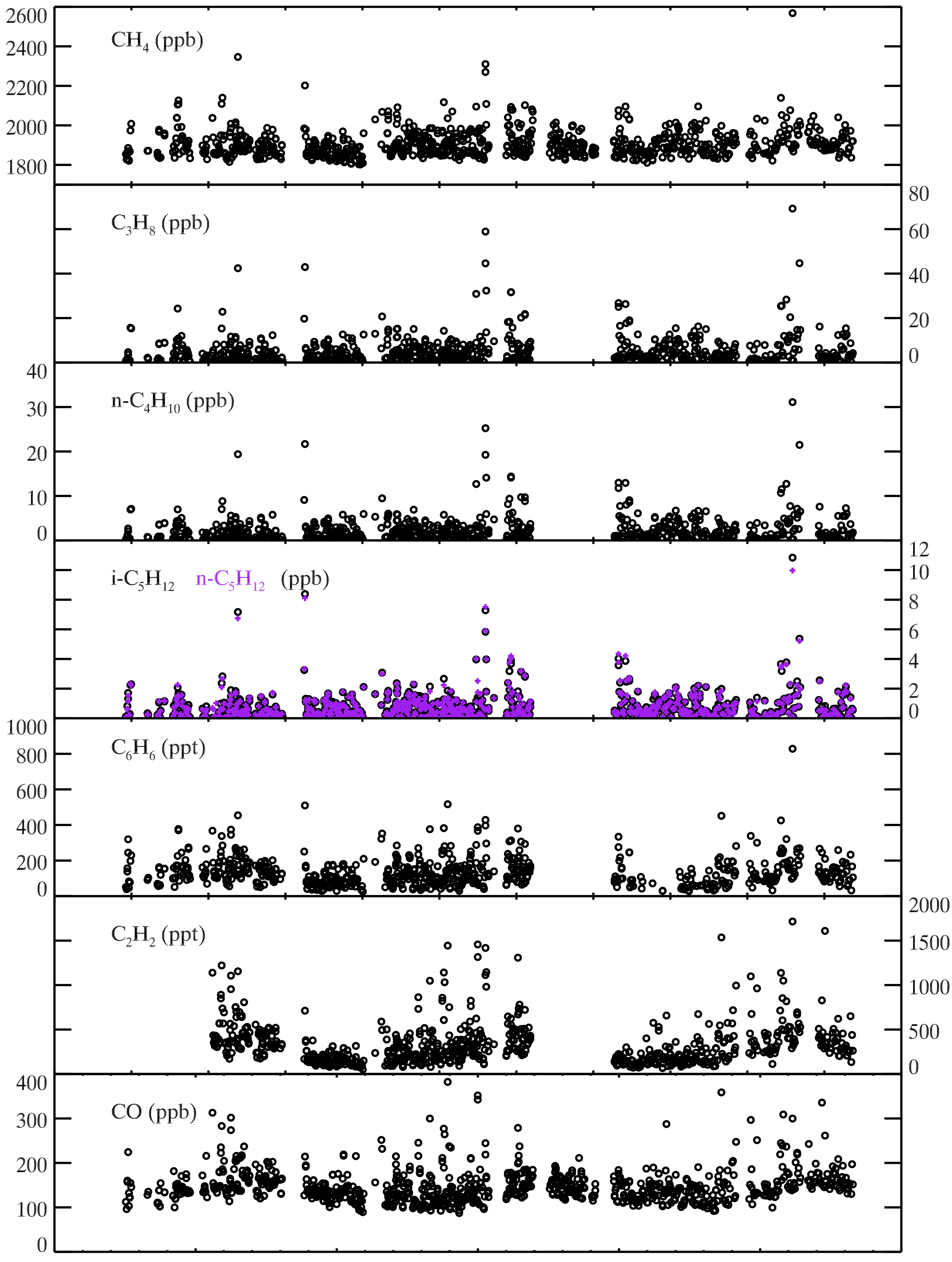
Table 3S: Total VOC and benzene source estimates for Weld County in different bottom-up inventories. Source categories may not sum to total *due to rounding.*
Sources: WRAP for year 2006 [Bar Ilan et al., 2008a], CDPHE for 2008 [CDPHE, personal communication], NEI 2005 [EPA, 2008], NEI 2008 [EPA, 2011b]

Species		**Total VOC**				**Benzene**		
Year		**2006**	**2008**	**2008**	**2005**	**2008**	**2008**	**2005**
Source		**WRAP**	**CDPHE**	**NEI**	**NEI**	**CDPHE**	**NEI**	**NEI**
unit		**Gg/yr**				**Mg/yr**		
On-Road			2533	2968	3532	95.4	121.4	160.1
Non-road + rail + aircraft			1596	1313	1626	44.2	36.0	45.9
Wood burning			232	-	187	8.8	-	5.7
Solvent utilization			201	1914	2819	-	-	31.6
Surface coating			1235	-	421	-	-	0.8
Oil and gas area		21145*	-	-	-	-	-	-
Oil and gas point	Large Condensate tanks	34790	17811	18163	-	21.3	21.5	1120.0
	Glycol dehydrators	218	220	-	-	15.1	-	47.6
	Gas sweetening	11	11	-	-	6.6	-	7.8
	Internal Combustion Engines	1996	1692	-	-	16.0	-	-
	Other	304	844	646	-	2.8	23.1	1.6
	Total	*37015*	*20628*	*18810*	*-*	*61.8*	*44.6*	*1177.0*
Gas stations/Gasoline bulk terminals			697	965	1270	8.0	11.1	11.8
Forest and prescribed fires			110		207	8.3	-	2.4
Fossil Fuel combustion Point (non O&G)			196	1880	651	0.5	16.5	3.9
Other point			547	680	335	1.0	15.6	12.3
Other area			1078		605	2.3		4.6
Total for available source categories		58160	29051	28530	11654	230.5	245.2	1454

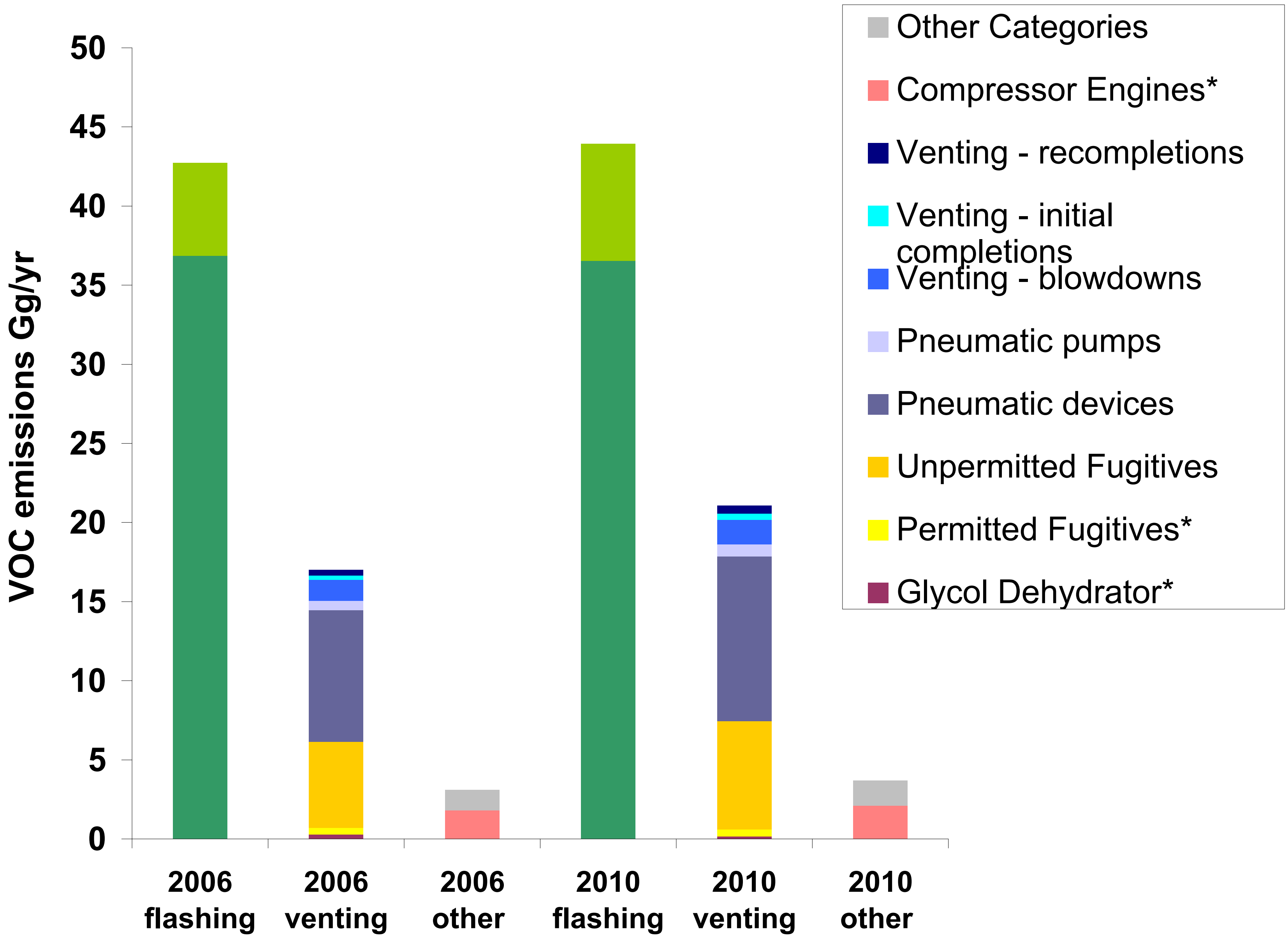
*Source categories included are: Pneumatic devices and pumps, small condensate tanks, fugitive emissions, heaters, process heaters, venting, truck loading, spills, NG production: flares, flanges and connections, and others.

Table 4S: Inventory and measurement derived molar ratios for the various data sets plotted on Figure 9. Flashing emissions composition is based on EPA TANK model runs for 16 condensate tanks located in the DJB and sampled in 2002 [CDPHE, personal communication 2010]. Venting emissions composition is based on an average raw gas weight composition profile provided by Bar-Ilan et al. [2008a] and derived private data from several natural gas producing companies in the DJB. To get a range of distribution for vented emissions, we use the molar composition provided by COGCC for raw gas samples collected at 77 wells in the DJB in December 2006. The BAO NE summer data and Mobile Lab data are the same as in Table 3. The Goldan et al. data for samples collected west of Boulder in February 1991 are based on Goldan et al. [1995] Table 1 and Figure 5.

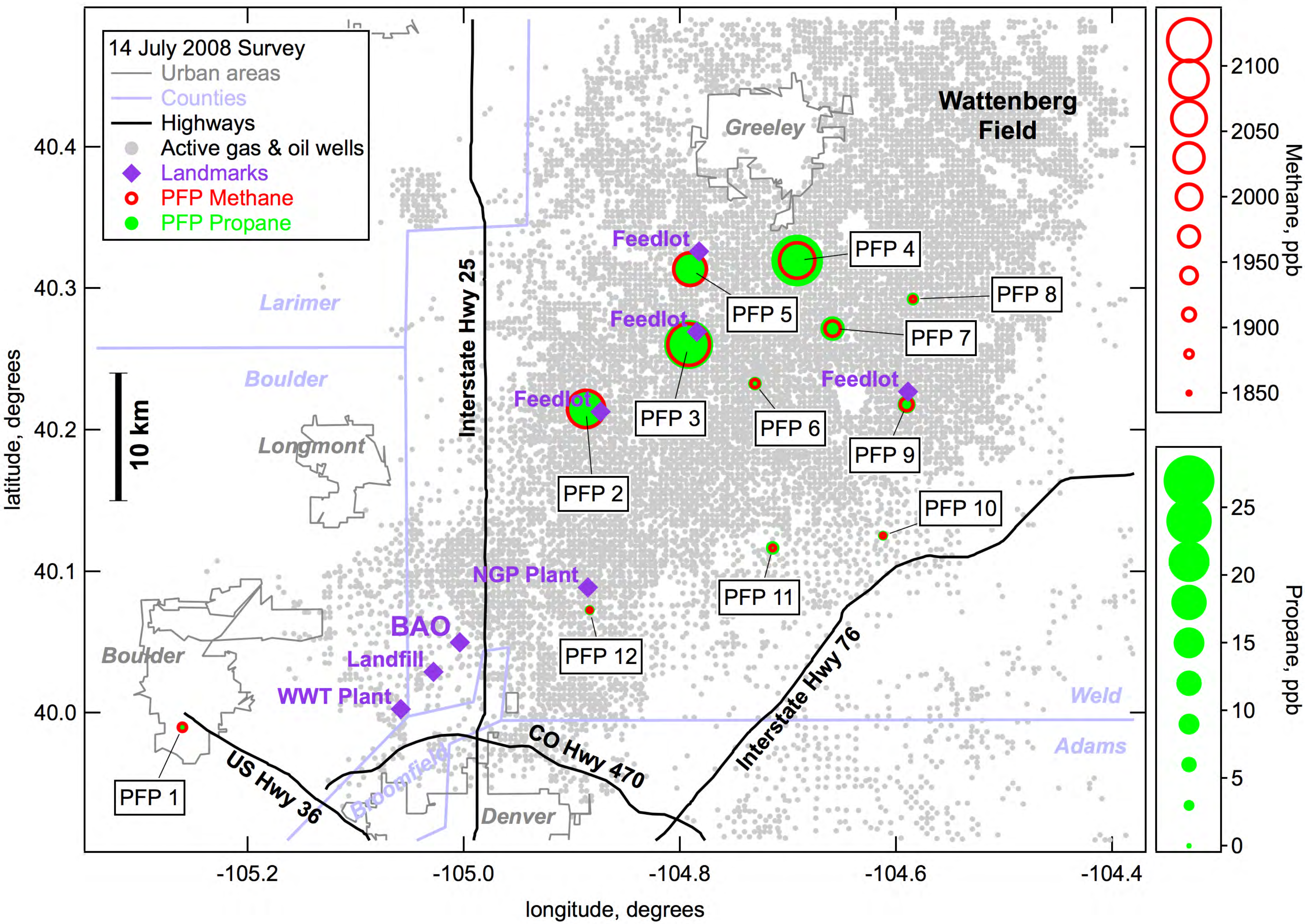
Data Set		C_3/C_1	nC_4/C_1	nC_4/C_3	iC_5/C_3	nC_5/C_3	iC_5/nC_4	nC_5/nC_4	iC_5/nC_5
WRAP Flashing emissions	Median	0.807	0.283	0.343	0.119	0.088	0.354	0.255	1.362
	Mean	0.654	0.271	0.339	0.123	0.088	0.354	0.262	1.271
	Min	0.290	0.074	0.252	0.032	0.029	0.104	0.093	1.006
	Max	1.896	0.618	0.519	0.194	0.158	0.643	0.340	1.999
WRAP Venting emissions		0.053	0.016	0.298	0.100	0.091	0.338	0.307	1.101
GWA raw gas	Median	0.065	0.015	0.245	0.066	0.054	0.270	0.231	1.179
	Mean	0.064	0.017	0.253	0.071	0.061	0.280	0.239	1.226
	Min	0.004	0.015	0.114	0.014	0.010	0.078	0.058	0.600
	Max	0.243	0.072	0.388	0.167	0.205	0.628	0.674	2.000
Bottom-up VOC inventory: WRAP Flashing + GWA Venting (mean profiles)		0.154	0.049	0.316	0.099	0.078	0.313	0.245	1.274
BAO NE -summer		0.104	0.051	0.447	0.141	0.150	0.297	0.315	0.957
Mobile Lab		0.095	0.050	0.510	0.185	0.186	0.423	0.414	1.046
Goldan et al.- all data		-	-	0.340	0.180	0.130	-	-	-
Goldan et al. C_3 source		-	-	0.625	-	-	0.600	0.380	-

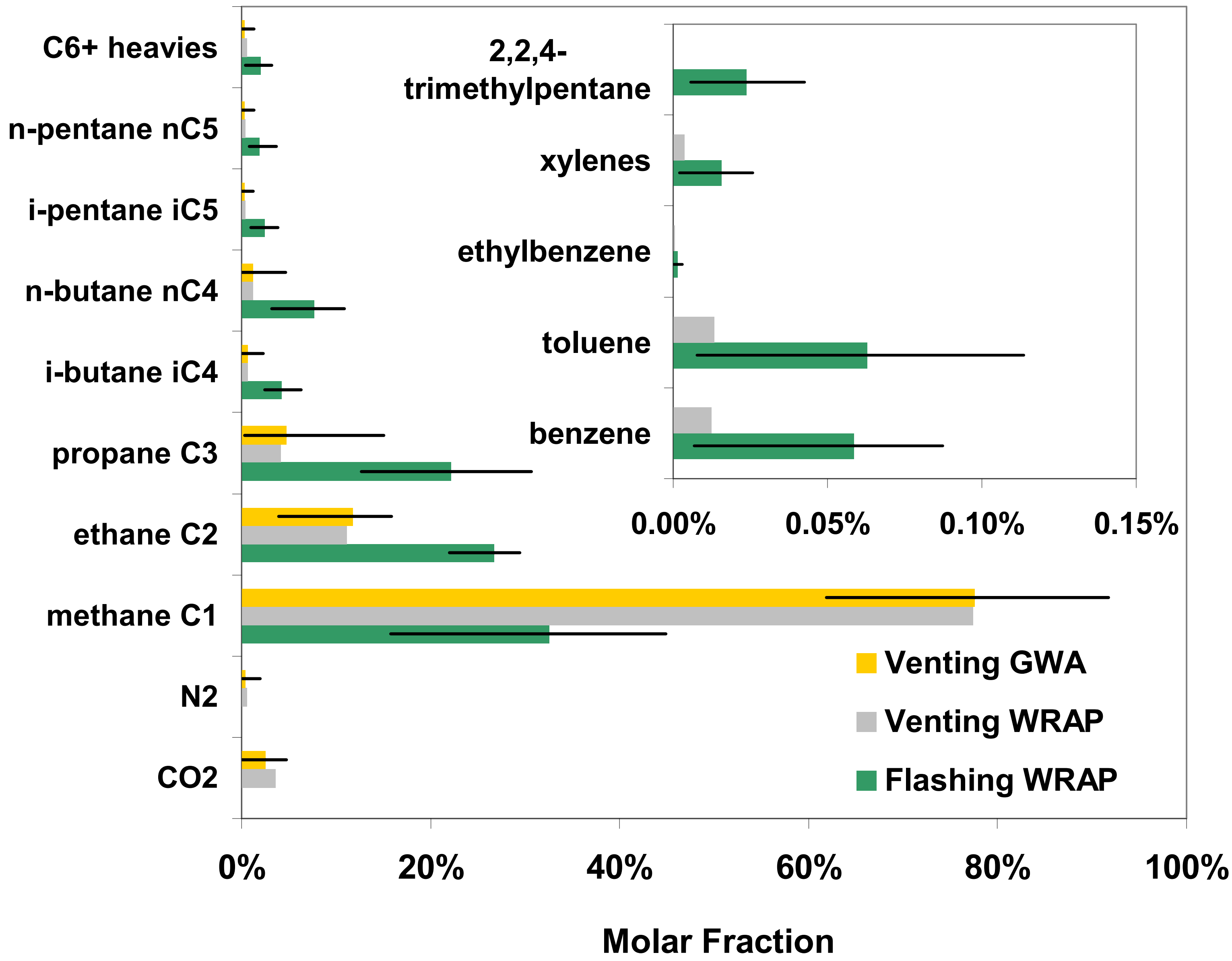


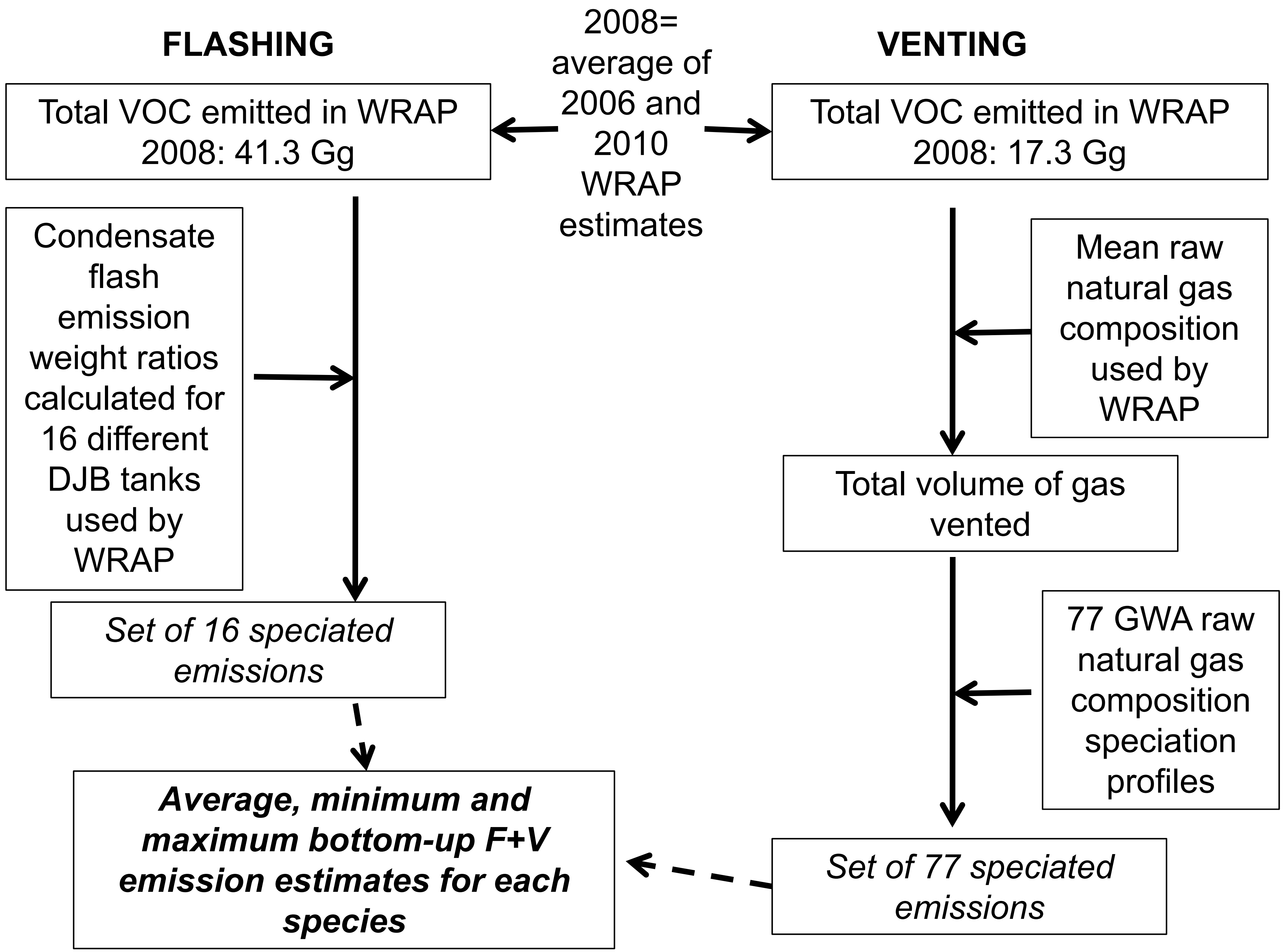
CH4 (ppb)
C3H8 (ppb)
n-C4H10 (ppb)
i-C5H12 n-C5H12 (ppb)
C6H6 (ppt)
C2H2 (ppt)
CO (ppb)

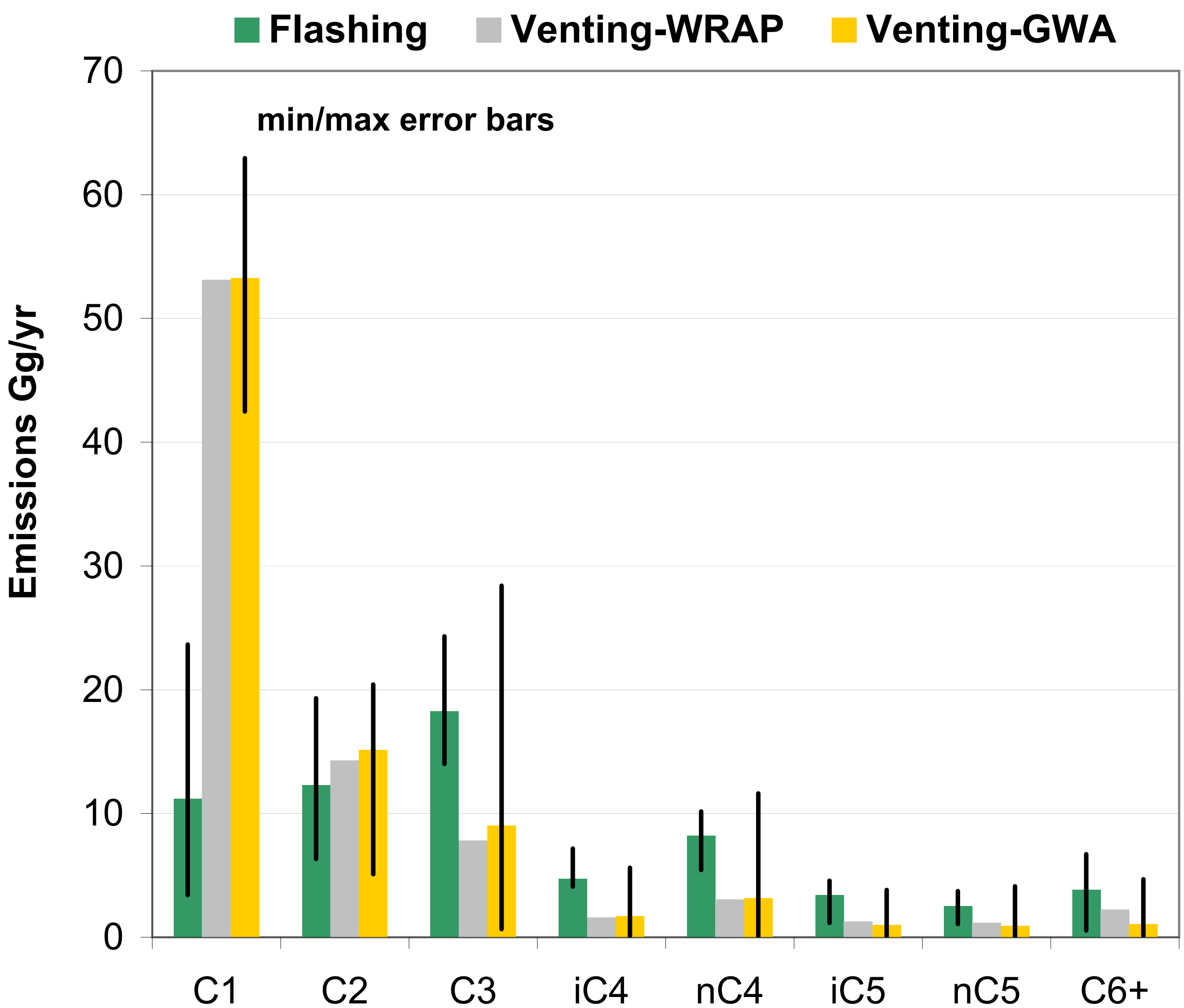


VOC emissions Gg/yr
50
45
40
35
30
25
20
15
10
5
0
2006 flashing
2006 venting
2006 other
2010 flashing
2010 venting
2010 other
Other Categories
Compressor Engines*
Venting - recompletions
Venting - initial completions
Venting - blowdowns
Pneumatic pumps
Pneumatic devices
Unpermitted Fugitives
Permitted Fugitives*
Glycol Dehydrator*


14 July 2008 Survey
Urban areas
Counties
Highways
Active gas & oil wells
Landmarks
PFP Methane
PFP Propane
Wattenberg Field
Greeley
Longmont
Boulder
Denver
Broomfield
Larimer
Boulder
Weld
Adams
10 km
Interstate Hwy 25
Interstate Hwy 76
CO Hwy 470
US Hwy 36
Feedlot
Feedlot
Feedlot
Feedlot
NGP Plant
BAO
Landfill
WWT Plant
PFP 1
PFP 2
PFP 3
PFP 4
PFP 5
PFP 6
PFP 7
PFP 8
PFP 9
PFP 10
PFP 11
PFP 12
latitude, degrees
40.0
40.1
40.2
40.3
40.4
longitude, degrees
-105.2
-105.0
-104.8
-104.6
-104.4
Methane, ppb
1850
1900
1950
2000
2050
2100
Propane, ppb
0
5
10
15
20
25


C6+ heavies
n-pentane nC5
i-pentane iC5
n-butane nC4
i-butane iC4
propane C3
ethane C2
methane C1
N2
CO2
0%
20%
40%
60%
80%
100%
Molar Fraction
2,2,4-trimethylpentane
xylenes
ethylbenzene
toluene
benzene
0.00%
0.05%
0.10%
0.15%
Venting GWA
Venting WRAP
Flashing WRAP


FLASHING
2008= average of 2006 and 2010 WRAP estimates
VENTING
Total VOC emitted in WRAP 2008: 41.3 Gg
Total VOC emitted in WRAP 2008: 17.3 Gg
Condensate flash emission weight ratios calculated for 16 different DJB tanks used by WRAP
Mean raw natural gas composition used by WRAP
Total volume of gas vented
Set of 16 speciated emissions
77 GWA raw natural gas composition speciation profiles
Average, minimum and maximum bottom-up F+V emission estimates for each species
Set of 77 speciated emissions



Flashing
Venting-WRAP
Venting-GWA
min/max error bars
Emissions Gg/yr
0
10
20
30
40
50
60
70
C1
C2
C3
iC4
nC4
iC5
nC5
C6+

Exhibit 3

Synapse
Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, MA 02139
Tel 617 661 3248 F 617 661 0599
www.synapse-energy.com

Memorandum

To: Craig Segall, Sierra Club Environmental Law Program

From: Rick Hornby (Synapse) and Dr. Carl Swanson (Swanson Energy Group)

Date: October 12, 2011

Re: Estimate of 2015 natural gas wellhead prices

This report summarizes our review of the estimate of 2015 natural gas prices the Environmental Protection Agency (EPA) used in the July 2011 Regulatory Impact Analysis (RIA) for its proposed oil and gas NSPS/NESHAP.[1] Our review indicates that the RIA's estimate of 2015 wellhead prices, at $4 per Mcf ($2008), is conservative and could cause the RIA to over-estimate net engineering compliance costs by $ 149 million in 2015 and by larger amounts in years after 2015.

Background

In its RIA the EPA calculates the projected benefits and costs of its proposed oil and gas NSPS/NESHAP. One of the projected benefits of certain of the proposed controls is the retention and sale of methane that would otherwise be co-emitted with Volatile Organic Compounds (VOCs). Tables 3-2, 3-3 and 3-4 of the RIA provide estimates of the reduction in estimated engineering compliance costs due to the revenues from recovering, and selling, the quantities of methane and condensate that would otherwise be co-emitted. RIA calculates the value of this methane in 2015 using an estimated wellhead price of $4.00/Mcf in 2008 dollars (EPA/RIA 2011, page 3-13). The RIA indicates that its estimate of 2015 wellhead prices is a particularly critical assumption. For example the RIA notes that a $1/Mcf increase in the wellhead price would reduce estimated engineering compliance costs by $180 million in 2008$.[2]

Review

The Sierra Club asked Synapse Energy Economics (Synapse) to assess whether the RIA used a realistic estimate of 2015 wellhead prices, and hence whether the RIA calculations of revenues from additional methane recovery are reasonable. Synapse began by collecting recent estimates of U.S. national gas production prices in 2015 for a "Reference Case" from as many public sources as possible. Table 1, attached, presents estimates obtained from eight different sources listed below and the vintage of each estimate. The eight sources are:

- Energy Information Administration (EIA)

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[1] US Environmental Protection Agency, Regulatory Impact Statement, Proposed New Source Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry, July 2011. (EPA/RIA 2011)
[2] *ibid.* page 3-13.

- Deutsche Bank AG
- IHS Global Insight
- Energy Ventures Analysis
- ICF International
- Deloitte Center for Energy Solutions
- Synapse Energy Economics
- NYMEX

Appendix A provides excerpts of the pages with the estimates from the public source documents.

The eight sources provide their estimates of natural gas production prices in 2015 for a range of pricing points as well as in a range of physical units and dollar values. In order to prepare an "apples-to-apples" comparison of projections for the same pricing point, physical units and dollar value as the RIA estimate we converted the estimate from each of the eight sources to a national average wellhead price expressed in constant 2008 $ per Mcf. Those conversions entailed some or all of the following adjustments:

- Reduce estimates provided for the Henry Hub (HH) by the applicable price differentials between the HH and the national average wellhead price.[3] The Deloitte and NYMEX estimates were reduced by the AEO 2011 price differential for 2015 of $0.525/MMBtu (2008$). The AESC 2011 estimate was reduced by $ 0.67 per MMBtu ($2008), the price differential from AEO 2011 High Shale case;

- Convert values reported in MMBtu to Mcf using the AEO 2011 conversion factor of 1.026 MMBtu per Mcf;

- Adjust estimates to constant 2008$ based upon the GDP deflator from the US Bureau of Economic Analysis (BEA) and inflation estimates used in AESC 2011; and

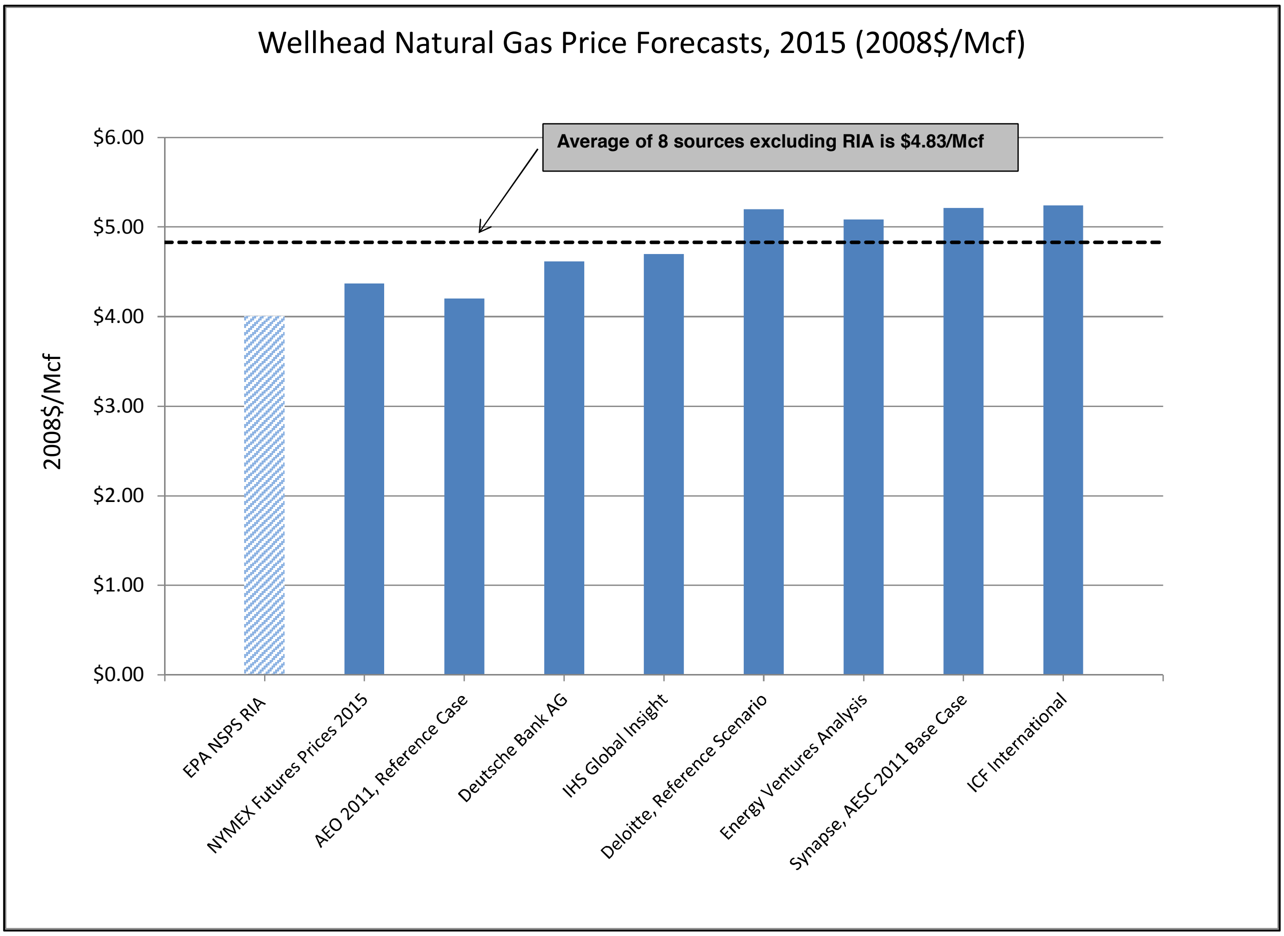
- Convert methane emissions in tons to Mcf using the RIA conversion factor of 48.04 Mcf per US short ton (page 3-22, footnote).

Table 1 presents the original estimates from each source as well as the factors we used to convert those estimates to wellhead prices in 2008$ per Mcf and the results of those calculations.

As indicated in Figure 1 and in Table 1, the RIA's estimate of $4 per Mcf is lower than any of the estimates from the other eight sources. We also understand that estimates of well-head prices in 2015 from two additional sources that provide estimates on a private subscription basis, PIRA and Wood Mackenzie, are also well above $4.00 per Mcf. Thus the RIA estimate of wellhead prices for 2015 is conservative.

[3] Henry Hub, located in southern Louisiana, is the major pricing point for natural gas in the US and the delivery point for natural gas futures.

Figure 1



The simple average of wellhead price estimates from the eight sources, i.e., excluding the RIA estimate, is $4.83/Mcf. Therefore the RIA estimate of $4.00/Mcf could be under-estimating the value of recovered gas in 2015 by $0.83/Mcf on average. After 2015 the RIA estimate would be under-estimating that value by an even greater amount since the eight sources we reviewed all estimate prices to be even higher after 2015.

As noted earlier, the RIA estimates that a $1/Mcf change in the wellhead price will reduce estimated engineering compliance costs by $180 million. That estimate implies that a $0.83/Mcf change would reduce estimated compliance costs by $149 million.[4] For example, applying the $0.83/Mcf to just the methane projected to be recovered via reduced emission completion (REC) represents approximately $128 million in additional product value each year.[5] (The methane projected to be recovered via REC from new and recompleted fractured gas is reported in Table 3-3 of the RIA).

[4] $180 millon * $0.83 / $1.00
[5] $0.83/Mcf * 48.04 Mcf / tons * (1.399 million tons + 1.810 million tons) per year from Table 3-3 of RIA.

Table 1: Natural Gas Price Forecasts for 2015

Forecasts		Estimates for 2015 reported in Forecasts					Forecasts of wellhead Prices in 2015	
Sources		Date	Units	$ Year	Location	Estimate for 2015	2008 $/MMBtu	2008$/Mcf
AEO 2011, Reference Case	(a)	Apr-11	$/Mcf	2009 $	L48 WH	$ 4.24	N/A	4.201
IHS Global Insight	(a)	Sep-10	$/Mcf	2009 $	L48 WH	$ 4.74		4.697
Energy Ventures Analysis	(a)	Feb-11	$/Mcf	2009 $	L48 WH	$ 5.13		5.083
Deutsche Bank AG	(a)	Jan-11	$/Mcf	2009 $	L48 WH	$ 4.66		4.618
ICF International	(a)	4th Q 2010	$/Mcf	2009 $	L48 WH	$ 5.29		5.242
Synapse, AESC 2011 Base Case	(b)	Jul-11	$/MMBtu	2011 $	HH	$ 5.91	5.080	5.212
Deloitte, Reference Scenario	(c)	Sep-11	$/MMBtu	2011 $	HH	$ 5.75	5.069	5.201
NYMEX Futures Prices	(d)	Average 9/16/2011 and 10/07/2011	$/MMBtu	2015 $	HH	$ 5.32	4.253	4.364
Average								**4.827**

Sources
(a) US EIA, *Annual Energy Outlook 2011*, April 26, 2011. (AEO 2011)
(b) Synapse Energy Economics, Inc., *Avoided Energy Supply Costs in New England: 2011 Report*. July 21, 2011
(c) Deloitte Center for Energy Solutions, *Navigating a Fractured Future*, September 2011, estimate from Figure 1.
(d) NYMEX, average of settlement prices for months in 2015 from 9/16/2011 and 10/07/2011

Conversion Factors

Dollar Values

	2009	2011	2015
GDP deflator 2008 = 1.0	1.0092	1.02790383	1.1126

Source: *Avoided Energy Supply Costs in New England: 2011 Report*, Appendix A)

MMBtu per Mcf of dry gas 1.026
Source: *AEO 2011*, Appendix G

Price Difference between Henry Hub and national average wellhead

Source *: AEO 2011*	0.530	2009$/MMBtu
	0.525	2008$/MMBtu
Source : AEO 2010, High Shale case	0.670	2008$/MMBtu

Appendix A

Excerpts of pages with estimates from public source documents

US EIA, *Annual Energy Outlook 2011*, April 26, 2011. (AEO 2011)

Synapse Energy Economics, *Avoided Energy Supply Costs in New England: 2011 Report*. July 21, 2011

Deloitte Center for Energy Solutions, *Navigating a Fractured Future*, September 2011, Figure 1.

NYMEX, average of settlement prices for months in 2015 from September 16, 2011 and October 7, 2011

Annual Energy Outlook 2011

With Projections to 2035

April 2011

U.S. Energy Information Administration
Office of Integrated and International Energy Analysis
U.S. Department of Energy
Washington, DC 20585

This publication is on the WEB at:
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Table 16. Comparison of natural gas projections, 2015, 2025, and 2035 (trillion cubic feet, except where noted)

Projection	2009	*AEO2011* Reference case	IHSGI	EVA	DB	ICF	ExxonMobil	INFORUM
		2015						
Dry gas production[a]	20.96	22.43	22.70	22.70	21.98	23.75	21.00	21.21
Net imports	**2.64**	**2.69**	**2.19**	**2.60**	**3.01**	**1.68**	**1.60**	**--**
Pipeline	2.23	2.33	1.46	2.20	1.53	1.26	--	--
LNG	0.41	0.36	0.73	0.40	1.48	0.42	--	--
Consumption	**22.71**	**25.11**	**24.89**	**24.70**	**25.17**	**25.30**	**23.00**[b]	**21.20**[c]
Residential	4.75	4.81	4.72	4.90	5.10	5.11	8.00[d]	4.67
Commercial	3.11	3.38	3.05	3.20	3.25	3.20	--	3.86
Industrial[e]	6.14	8.05	6.64	6.90	6.70	6.88	7.00	7.06
Electricity generators[f]	6.89	6.98	8.58	7.60	8.01	7.81	8.00	5.61
Others[g]	1.82	1.90	1.90	2.10	2.11	2.29	0.00[h]	--
Lower 48 wellhead price (2009 dollars per thousand cubic feet)	3.71	4.24	4.74	5.13	4.66	5.29	--	--
End-use prices (2009 dollars per thousand cubic feet)								
Residential	12.20	10.39	11.85	--	--	9.76	--	--
Commercial	9.94	8.60	10.00	--	--	8.77	--	--
Industrial[i]	5.39	5.10	7.18	--	--	6.59	--	--
Electricity generators	4.94	4.79	5.49	--	--	6.27	--	--
		2025						
Dry gas production[a]	20.96	23.98	26.22	24.70	23.48	29.04	24.00	22.67
Net imports	**2.64**	**1.08**	**2.74**	**2.00**	**2.20**	**1.31**	**2.00**	**--**
Pipeline	2.23	0.74	2.01	1.60	1.55	0.68	--	--
LNG	0.41	0.34	0.73	0.40	0.66	0.63	--	--
Consumption	**22.71**	**25.07**	**28.87**	**25.70**	**25.69**	**30.28**	**26.10**[b]	**24.84**[c]
Residential	4.75	4.83	4.62	5.00	5.52	5.20	7.00[d]	4.84
Commercial	3.11	3.56	2.98	3.30	3.25	3.04	--	4.13
Industrial[e]	6.14	8.10	6.47	7.50	6.70	7.21	7.00	7.88
Electricity generators[f]	6.89	6.66	12.64	7.70	8.21	12.18	12.00	7.99
Others[g]	1.82	1.92	2.17	2.20	2.01	2.65	0.10[h]	--
Lower 48 wellhead price (2009 dollars per thousand cubic feet)	3.71	5.43	4.73	6.46	7.15	6.10	--	--
End-use prices (2009 dollars per thousand cubic feet)								
Residential	12.20	12.15	11.59	--	--	10.47	--	--
Commercial	9.94	10.03	9.81	--	--	9.52	--	--
Industrial[i]	5.39	6.33	7.09	--	--	7.35	--	--
Electricity generators	4.94	5.91	5.43	--	--	7.09	--	--

-- = not reported.
See notes at end of table.

(continued on page 99)

Table 15. Comparison of electricity projections, 2015, 2025, and 2035: ***AEO2011***: AEO2011 National Energy Modeling System, run AEO2011.D020911A. **EVA**: Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (February 2011). **IHSGI**: IHS/Global Insight, Inc., *2010 Energy Outlook* (Lexington, MA, September 2010). **ICF:** ICF International, ICD Integrated Energy Outlook (Fourth Quarter, 2010). **INFORUM:** Inforum Long-term Interindustry Forecasting Tool (Lift) Model (2010).

Table 16. Comparison of natural gas projections, 2015, 2025, and 2035: *AEO2011*: AEO2011 National Energy Modeling System, run REF2011.D020911A. **IHSGI**: IHS/Global Insight, Inc., *U.S. Energy Outlook* (Lexington, MA, September 2010). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (February 2011). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski (January 11, 2011). **ICF**: ICF International, ICD Integrated Energy Outlook (Fourth Quarter, 2010). **ExxonMobil**: Exxon Mobil Corporation, *The Outlook for Energy: A View to 2030* (Irving, TX, 2010). **INFORUM:** Inforum Long-term Interindustry Forecasting Tool (Lift) Model (2010).

Table 17. Comparison of liquids projections, 2015, 2025, and 2035: ***AEO2011***: AEO2011 National Energy Modeling System, run AEO2011.D0209A. **DB:** Deutsche Bank AG, email from Adam Sieminski (January 11, 2011). **ICF:** ICF International, ICD Integrated Energy Outlook (Fourth Quarter, 2010). **IHSGI:** IHS/Global Insight, Inc., *U.S. Energy Outlook* (Lexington, MA, September 2010). **INFORUM:** Inforum Long-term Interindustry Forecasting Tool (Lift) Model (2010).**P&G:** Purvin and Gertz, Inc., *2010 Global Petroleum Market Outlook*, Vol. 2, Table III-2 (2010).

Table 18. Comparison of coal projections, 2015, 2025, 2030, and 2035: ***AEO2011***: AEO2011 National Energy Modeling System, run REF2011.D020911A. **DB**: Deutsche Bank AG, email from Adam Sieminski (January 11, 2011). **EVA**: Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (February 2011). **ICF**: ICF International, ICD Integrated Energy Outlook (Fourth Quarter, 2010). **INFORUM**: INFORUM Long-term Interindustry Forecasting Tool (Lift) Model (2010). **WM**: Wood Mackenzie, *Fall 2010 Long-Term US Thermal Coal Outlook.*

Figure notes and sources

Figure 1. U.S. liquids fuel consumption, 1970-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** AEO2011 National Energy Modeling System, run REF2011. D020911A.

Figure 2. U.S. natural gas production, 1990-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** AEO2011 National Energy Modeling System, run REF2011. D020911A.

Figure 3. U.S. nonhydropower renewable electricity generation, 1990-2035: U.S. Energy Information Administration, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** AEO2011 National Energy Modeling System, run REF2011.D020911A.

Figure 4. U.S. carbon dioxide emissions by sector and fuel, 2005 and 2035: History: U.S. Energy Information Administration, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** AEO2011 National Energy Modeling System, run REF2011.D020911A.

Figure 5. Surface coal mining productivity in Central Appalachia, 1980-2035: History: U.S. Energy Information Administration, Form EIA-7A, "Coal Production Report," and U.S. Department of Labor, Mine Safety and Health Administration, Form 7000-2, "Quarterly Mine Employment and Coal Production Report." **Projections:** AEO2011 National Energy Modeling System, run REF2011. D020911A and AEO2010 National Energy Modeling System, run AEO2010R.D111809A.

Figure 6. Total energy consumption in three cases, 2005-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** AEO2011 National Energy Modeling System, runs REF2011.D020911A, NOSUNSET.D030711A, and EXTENDED.D031011A.

Figure 7. Total liquid fuels consumption for transportation in three cases, 2005-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** AEO2011 National Energy Modeling System, runs REF2011.D020911A, NOSUNSET.D030711A, and EXTENDED.D031011A.

Figure 8. Renewable electricity generation in three cases, 2005-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** AEO2011 National Energy Modeling System, runs REF2011.D020911A, NOSUNSET.D030711A, and EXTENDED.D031011A.

Figure 9. Electricity generation from natural gas in three cases, 2005-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** AEO2011 National Energy Modeling System, runs REF2011.D020911A, NOSUNSET.D030711A, and EXTENDED.D031011A.

Figure 10. Energy-related carbon dioxide emissions in three cases, 2005-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** AEO2011 National Energy Modeling System, runs REF2011.D020911A, NOSUNSET.D030711A, and EXTENDED.D031011A.

Synapse
Energy Economics, Inc.

Avoided Energy Supply Costs in New England:

2011 Report

July 21, 2011

Amended August 11, 2011

AUTHORS

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Exhibit 3-17: Forecast Annual Average Wholesale Gas Commodity Prices in New England (2011 Dollar per MMBtu)

	Henry Hub	CT	RI	MA	NH	ME	New England (excluding VT)
2011	$ 4.37	$5.11	$5.11	$5.02	$5.02	$5.02	$5.07
2012	4.91	5.74	5.74	5.64	5.64	5.64	5.69
2013	5.10	5.97	5.97	5.86	5.86	5.86	5.92
2014	5.29	6.19	6.19	6.08	6.08	6.08	6.13
2015	5.91	6.92	6.92	6.80	6.80	6.80	6.86
2016	5.96	6.97	6.97	6.85	6.85	6.85	6.91
2017	5.93	6.94	6.94	6.82	6.82	6.82	6.88
2018	5.95	6.96	6.96	6.84	6.84	6.84	6.90
2019	5.98	7.00	7.00	6.88	6.88	6.88	6.94
2020	6.06	7.09	7.09	6.97	6.97	6.97	7.03
2021	6.16	7.20	7.20	7.08	7.08	7.08	7.14
2022	6.25	7.31	7.31	7.19	7.19	7.19	7.25
2023	6.52	7.63	7.63	7.50	7.50	7.50	7.56
2024	6.72	7.86	7.86	7.73	7.73	7.73	7.80
2025	6.78	7.94	7.94	7.80	7.80	7.80	7.87
2026	6.89	8.06	8.06	7.92	7.92	7.92	7.99

Notes

Connecticut and Rhode Island per basis-differential ratios to Algonquin market hub.

Massachusetts, Maine, and New Hampshire per basis differential ratio to Tennessee Zone 6 market hub.

New England, excluding Vermont, is based on the average basis-differential coefficient to Algonquin and Tennessee Zone 6.

3.7.3. Impact of New Regional Supplies on Wholesale Prices in New England

To date, increases in the quantity of supply to New England from eastern Canada and new LNG facilities have not led to major reductions in the price of gas in New England. Instead, those supplies have tended to displace gas that would otherwise have been delivered into the region from the Mid-Atlantic Region, a much larger market. In the future, as the sources of gas supply to the Eastern United States shift from the traditional Southwestern producing regions to new producing basins such as the Marcellus Shale and Rocky Mountain producing areas, the basis differential between New England and the Henry Hub may decline.

Deloitte.

Navigating a fractured future
Insights into the future of the North American natural gas market

A report by the Deloitte Center for Energy Solutions and Deloitte MarketPoint

Deloitte Center for Energy Solutions

Contents

Introduction

Over the past decade, the North American natural gas industry has transformed vast, previously uneconomic shale gas deposits into valuable energy resources. While the so-called "shale gas revolution" has dramatically revitalized natural gas exploration and production, increased supplies combined with the slowdown in demand resulting from the recent economic events, have sent North American gas prices down dramatically.

Accordingly, North American gas producers are currently facing a great deal of uncertainty. To unlock the potential of shale gas resources, large investments are needed. However, the investment decisions require an understanding of the rapidly changing market dynamics related to new gas supplies and uncertain demand growth. Those decisions are complicated by a plethora of interrelated domestic and international forces that influence the natural gas market in North America.

Producers are asking many important questions, including:

- How long will United States (U.S.) natural gas prices stay low, and will they ever achieve parity to other global markets?
- Will U.S. shale gas production continue its rapid growth and eventually overtake conventional production?
- Will low natural gas prices stimulate significant additional demand in the U.S. for power generation and for other sectors of the economy?
- How do changes in shale gas costs impact U.S. production and prices?
- How will the anticipated increase in global liquefied natural gas (LNG) supply affect the U.S.?
- Will the U.S. ever import large volumes of LNG, and how much of the existing regasification capacity will be utilized?
- Alternatively, will the U.S. become a long-term exporter of LNG?
- How will continuation of China's ravenous appetite for energy affect U.S. and world gas prices?
- How will the announced nuclear shutdown in Japan, Germany, and other countries affect worldwide gas demand, and what are the implications for the U.S.?

In order to address many of these questions, Deloitte utilized the analytical capabilities of Deloitte MarketPoint LLC ("Deloitte MarketPoint"). Deloitte MarketPoint applied its integrated North American and World Gas Models to analyze the future of North American gas markets under a range of assumptions. This paper summarizes the findings of several scenarios regarding the future of North American and global gas markets and offers related strategic insights.

North American gas producers are currently facing a great deal of uncertainty.

Executive summary

For this report, Deloitte MarketPoint used its World Gas Model (WGM) to analyze North American gas markets over the next two decades. The model, based on sound economic theories and detailed representations of global gas demand, supply basins, and infrastructure, projects market clearing prices and quantities over a long time horizon on a monthly basis. The model also helps provide a better understanding of fundamental market drivers and their potential impacts.

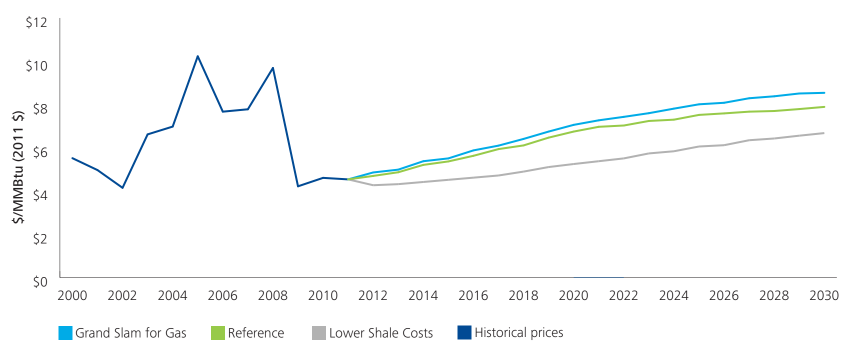
Our Reference scenario assumes current market trajectories without any major regulatory intervention. Under this scenario, worldwide economic growth rebounds fairly quickly from the recent downturn and resumes steady growth. World gas demand grows by 1.9% per annum through 2030. It assumes no U.S. regulatory policy restricting emissions of carbon dioxide (CO2), although there is tightening of mercury, nitrogen oxides (NOx), and sulfur oxides (SOx) regulations. Even without carbon legislation, gas demand for power generation grows rapidly as gas becomes the fuel of choice for new domestic power plants. It also assumes no new regulations or restrictions on the application of the hydrofracking process to produce shale gas. This scenario does not include the potential impacts from the announced shutdown of nuclear power plants in the aftermath of the Japanese nuclear disaster in March 2011.

We also present two alternative scenarios, one altering demand and the other altering supply. The first, referred to here as the "Grand Slam for Gas," is roughly based upon the high demand scenario described by the International Energy Agency's World Energy Outlook 2011. Under this scenario, global demand rapidly escalates as Asian demand, primarily from China, continues to grow at a rapid rate. Gas demand in China is projected to equal all of European gas demand by 2035. Furthermore, some leading nuclear power countries, including Japan, Germany, and the U.S., are assumed to shut down or scale back their nuclear energy production or expansion plans, leading to increased demand for natural gas.

Under the second scenario, referred to here as "Lower Shale Costs," we assessed the impact of lower shale gas production costs. While large volumes of shale gas are projected in our Reference case, much of it requires a relatively high wellhead price (> $8 per million British thermal units (MMBtu)) to make production economically viable. What if the costs were dramatically lower as some have suggested? In the Lower Shale Costs scenario, we lowered the cost to produce shale gas by about 50% to assess the impact on domestic and global prices.

Figure 1 shows the various paths that benchmark Henry Hub prices follow under the Reference scenario and two alternative scenarios. Prices in this and other charts are shown in real terms (i.e., 2011 dollars), unless otherwise stated. The projections of Henry Hub prices rise above current levels under all three scenarios. In an absolute sense, relative to the Reference scenario, the price impact of the lower shale gas cost scenario is much greater than the impact of the higher gas demand scenario.

Figure 1. Henry Hub price projection under the reference and alternative scenarios



PRODUCT SYMBOL	CONTRACT MONTH	CONTRACT YEAR	CONTRACT DAY	CONTRACT	PRODUCT DESCRIPTION	OPEN	HIGH	HIGH AB INDICATOR	LOW	LOW AB INDICATOR	LAST	LAST AB INDICATOR	SETTLE	PT CHG	EST. VOL	PRIOR SETTLE	PRIOR VOL	PRIOR INT	TRADEDATE
HH	1	2015		HHF15	Natural Gas Last Day Futures								5.612	-0.001	0	5.613			9/16/2011
HH	2	2015		HHG15	Natural Gas Last Day Futures								5.582	0.002	0	5.58			9/16/2011
HH	3	2015		HHH15	Natural Gas Last Day Futures								5.502	0.007	0	5.495			9/16/2011
HH	4	2015		HHJ15	Natural Gas Last Day Futures								5.227	0.017	0	5.21			9/16/2011
HH	5	2015		HHK15	Natural Gas Last Day Futures								5.237	0.017	0	5.22			9/16/2011
HH	6	2015		HHM15	Natural Gas Last Day Futures								5.265	0.017	0	5.248			9/16/2011
HH	7	2015		HHN15	Natural Gas Last Day Futures								5.3	0.017	0	5.283			9/16/2011
HH	8	2015		HHQ15	Natural Gas Last Day Futures								5.322	0.017	0	5.305			9/16/2011
HH	9	2015		HHU15	Natural Gas Last Day Futures								5.329	0.017	0	5.312			9/16/2011
HH	10	2015		HHV15	Natural Gas Last Day Futures								5.357	0.017	0	5.34			9/16/2011
HH	11	2015		HHX15	Natural Gas Last Day Futures								5.482	0.016	0	5.466			9/16/2011
HH	12	2015		HHZ15	Natural Gas Last Day Futures								5.71	0.022	0	5.688			9/16/2011

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Trade Date

Friday, October 07 2011

Daily Settlements for Henry Hub Natural Gas Futures (FINAL) **Trade Date:** 10/07/2011

Month	Open	High	Low	Last	Change	Settle	Estimated Volume	Prior Day Open Interest
NOV 11	3.595	3.600	3.470	3.484	-.117	3.481	176,388	206,549
DEC 11	3.916	3.916	3.807	3.821	-.096	3.820	94,167	91,361
JAN 12	4.085	4.085	3.985	3.998	-.091	4.000	94,677	185,422
FEB 12	4.111	4.111	4.010	4.017B	-.091	4.022	20,165	60,931
MAR 12	4.077	4.077	3.976	4.030	-.090	3.990	19,465	70,812
APR 12	4.070	4.070	3.965	4.015	-.090	3.977	18,573	87,237
MAY 12	4.063	4.070	4.000	4.040	-.088	4.011	3,618	24,806
JUN 12	4.141	4.141	4.044A	4.046B	-.087	4.051	1,802	14,306
JLY 12	4.142	4.149B	4.088A	4.090B	-.086	4.095	2,263	12,692
AUG 12	4.150	4.156B	4.112A	4.113B	-.086	4.118	1,255	11,715
SEP 12	4.166	4.173B	4.112A	4.114B	-.086	4.118	1,152	9,037
OCT 12	4.211	4.211	4.146A	4.149B	-.086	4.152	6,693	46,446
NOV 12	4.330	4.341B	4.298A	4.300B	-.082	4.304	3,067	10,452
DEC 12	4.656	4.656	4.590A	4.590A	-.079	4.595	1,138	14,046
JAN 13	4.795	4.800	4.737	4.737	-.077	4.741	2,797	23,792
FEB 13	4.755	4.756B	4.716A	4.716A	-.077	4.717	232	4,783
MAR 13	4.692	4.692	4.659A	4.659A	-.077	4.653	430	12,475
APR 13	4.575	4.575	4.535	4.535	-.077	4.534	1,062	19,397
MAY 13	4.568	4.568	4.568	4.568	-.077	4.552	3	2,611
JUN 13	4.603	4.603	4.584A	4.584A	-.077	4.581	7	1,575
JLY 13	-	-	4.625A	4.625A	-.077	4.623	-	1,545
AUG 13	-	-	4.641A	4.641A	-.077	4.640	-	1,472
SEP 13	4.670	4.670	4.654A	4.654A	-.077	4.646	1	1,048
OCT 13	4.705	4.709B	4.673	4.676A	-.077	4.673	582	6,608
NOV 13	-	-	4.802A	4.802A	-.077	4.797	12	1,005
DEC 13	5.090	5.090	5.036A	5.036A	-.077	5.027	14	6,217
JAN 14	-	-	5.155A	5.155A	-.076	5.147	9	3,675
FEB 14	-	-	-	-	-.076	5.112	8	422
MAR 14	-	-	-	-	-.076	5.027	-	992
APR 14	4.830	4.830	4.815	4.815	-.068	4.812	2	3,372
MAY 14	4.860	4.860	4.833	4.833	-.068	4.822	3	544
JUN 14	4.868	4.868	4.868	4.868	-.068	4.850	1	266
JLY 14	4.901	4.901	4.901	4.901	-.068	4.885	1	527
AUG 14	4.919	4.919	4.919	4.919	-.068	4.907	2	319
SEP 14	4.925	4.925	4.925	4.925	-.068	4.914	1	384
OCT 14	4.958	4.958	4.958	4.958	-.068	4.942	3	782
NOV 14	-	-	-	-	-.066	5.064	-	314
DEC 14	-	-	-	-	-.064	5.286	-	584
JAN 15	-	-	5.425A	5.425A	-.062	5.403	-	602
FEB 15	-	-	-	-	-.062	5.368	-	191
MAR 15	-	-	-	-	-.062	5.283	-	389
APR 15	-	-	-	-	-.049	5.048	-	1,916
MAY 15	-	-	-	-	-.049	5.058	-	505
JUN 15	-	-	-	-	-.049	5.086	-	1,198
JLY 15	-	-	-	-	-.049	5.121	-	224
AUG 15	-	-	-	-	-.049	5.143	-	555
SEP 15	-	-	-	-	-.049	5.150	-	149
OCT 15	-	-	-	-	-.049	5.180	-	209
NOV 15	-	-	-	-	-.047	5.302	-	103
DEC 15	-	-	5.550A	5.550A	-.045	5.527	-	6,900
JAN 16	-	-	-	-	-.043	5.644	-	45
FEB 16	-	-	-	-	-.043	5.609	-	33
MAR 16	-	-	-	-	-.043	5.524	-	141
APR 16	-	-	-	-	-.038	5.254	-	177
MAY 16	-	-	-	-	-.038	5.264	-	89
JUN 16	-	-	-	-	-.038	5.292	-	209
JLY 16	-	-	-	-	-.038	5.327	-	80

Exhibit 4

AEO2012 Early Release Overview

Executive summary

Projections in the *Annual Energy Outlook 2012* (*AEO2012*) Reference case focus on the factors that shape U.S. energy markets in the long term, under the assumption that current laws and regulations remain generally unchanged throughout the projection period. The *AEO2012* Reference case provides the basis for examination and discussion of energy market trends and serves as a starting point for analysis of potential changes in U.S. energy policies, rules, or regulations or potential technology breakthroughs. Some of the highlights in the *AEO2012* Reference case include:

Projected growth of energy use slows over the projection period, reflecting an extended economic recovery and increasing energy efficiency in end-use applications

Projected transportation energy demand grows at an annual rate of 0.2 percent from 2010 through 2035 in the Reference case, and electricity demand grows by 0.8 percent per year. Energy consumption per capita declines by an average of 0.5 percent per year from 2010 to 2035. The energy intensity of the U.S. economy, measured as primary energy use in British thermal units (Btu) per dollar of gross domestic product (GDP) in 2005 dollars, declines by 42 percent from 2010 to 2035.

Domestic crude oil production increases

Domestic crude oil production has increased over the past few years, reversing a decline that began in 1986. U.S. crude oil production increased from 5.1 million barrels per day in 2007 to 5.5 million barrels per day in 2010. Over the next 10 years, continued development of tight oil, in combination with the ongoing development of offshore resources in the Gulf of Mexico, pushes domestic crude oil production in the Reference case to 6.7 million barrels per day in 2020, a level not seen since 1994. Even with a projected decline after 2020, U.S. crude oil production remains above 6.1 million barrels per day through 2035.

With modest economic growth, increased efficiency, growing domestic production, and continued adoption of nonpetroleum liquids, net petroleum imports make up a smaller share of total liquids consumption

U.S. dependence on imported petroleum liquids declines in the *AEO2012* Reference case, primarily as a result of growth in domestic oil production by more than 1 million barrels per day by 2020; an increase in biofuels use to more than 1 million barrels per day crude oil equivalent by 2024; and modest growth in transportation sector demand through 2035. Net petroleum imports as a share of total U.S. liquid fuels consumed drop from 49 percent in 2010 to 36 percent in 2035 in *AEO2012* (Figure 1). Proposed fuel economy standards covering vehicle model years 2017 through 2025 that are not included in the Reference case would further reduce projected liquids use and the need for liquids imports.

Natural gas production increases throughout the projection period

Much of the growth in natural gas production is a result of the application of recent technological advances and continued drilling in shale plays with high concentrations of natural gas liquids and crude oil, which have a higher value in energy equivalent terms than dry natural gas. Shale gas production increases from 5.0 trillion cubic feet in 2010 (23 percent of total U.S. dry gas production) to 13.6 trillion cubic feet in 2035 (49 percent of total U.S. dry gas production) (Figure 2).

Figure 1. U.S. liquid fuels supply, 1970-2035 (million barrels per day)

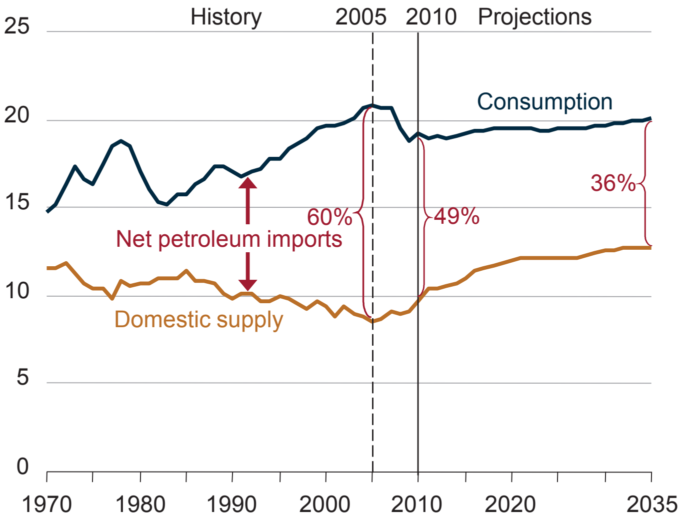
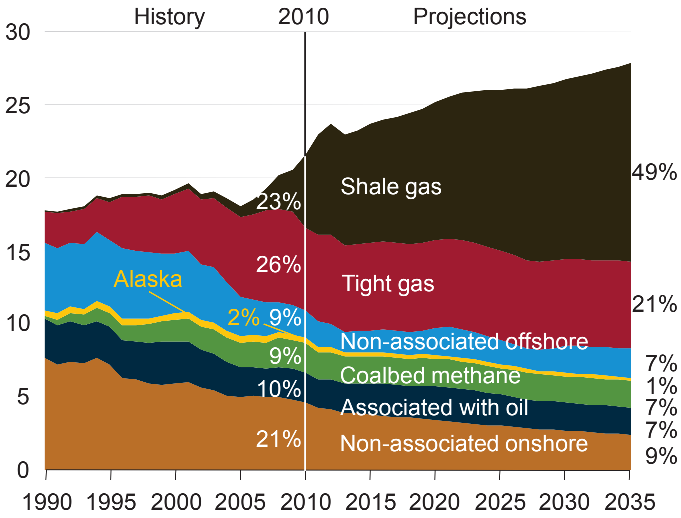


Figure 2. U.S. natural gas production, 1990-2035 (trillion cubic feet)



Expected changes in the *AEO2012* complete release

The Reference case results shown in the *AEO2012* Early Release will vary somewhat from those included in the complete *Annual Energy Outlook (AEO)* that will be released in spring 2012, because some data and model updates were not available for inclusion in the Early Release. In particular, the complete *AEO2012* will include the Mercury and Air Toxics Standards issued by the U.S. Environmental Protection Agency (EPA) in December 2011; updated historical data and equations in the transportation sector, based on revised data from the National Highway Traffic Safety Administration (NHTSA) and the Federal Highway Administration; a new model for cement production in the industrial sector; a revised long-term macroeconomic projection based on an updated long-term projection from IHS Global Insight, Inc.; and an updated representation of biomass supply.

U.S. production of natural gas is expected to exceed consumption early in the next decade

The United States is projected to become a net exporter of liquefied natural gas (LNG) in 2016, a net pipeline exporter in 2025, and an overall net exporter of natural gas in 2021. The outlook reflects increased use of LNG in markets outside of North America, strong domestic natural gas production, reduced pipeline imports and increased pipeline exports, and relatively low natural gas prices in the United States compared to other global markets.

Use of renewable fuels and natural gas for electric power generation rises

The natural gas share of electric power generation increases from 24 percent in 2010 to 27 percent in 2035, and the renewables share grows from 10 percent to 16 percent over the same period. In recent years, the U.S. electric power sector's historical reliance on coal-fired power plants has begun to decline. Over the next 25 years, the projected coal share of overall electricity generation falls to 39 percent, well below the 49-percent share seen as recently as 2007 (Figure 3), because of slow growth in electricity demand, continued competition from natural gas and renewable plants, and the need to comply with new environmental regulations.

Total U.S. energy-related carbon dioxide emissions remain below their 2005 level through 2035

Energy-related carbon dioxide (CO_2) emissions grow by 3 percent from 2010 to 2035, to a total of 5,806 million metric tons in 2035. They are more than 7 percent below their 2005 level of 5,996 million metric tons in 2020 and are still below the 2005 level at the end of the projection period (Figure 4). Emissions per capita fall by an average of 1 percent per year from 2005 to 2035, as growth in demand for transportation fuels is moderated by higher energy prices and Federal corporate average fuel economy (CAFE) standards, and as electricity-related emissions are tempered by efficiency standards, State renewable portfolio standard (RPS) requirements, competitive natural gas prices that dampen coal use by electricity generators, and the need to comply with new environmental regulations. Proposed fuel economy standards covering model years 2017 through 2025 that are not included in the Reference case would further reduce projected energy use and emissions.

Introduction

In preparing the *AEO2012* Reference case, the U.S. Energy Information Administration (EIA) evaluated a wide range of trends and issues that could have major implications for U.S. energy markets. This overview presents the *AEO2012* Reference case and compares it with the *AEO2011* Reference case released in April 2011 (see Table 1 on pages 12-13). Because of the uncertainties inherent in any energy market projection, the Reference case results should not be viewed in isolation. Readers are encouraged to review the alternative cases when the complete *AEO2012* publication is released, in order to gain perspective on how variations in key assumptions can lead to different outlooks for energy markets.

Figure 3. Electricity generation by fuel, 1990-2035 (trillion kilowatthours per year)

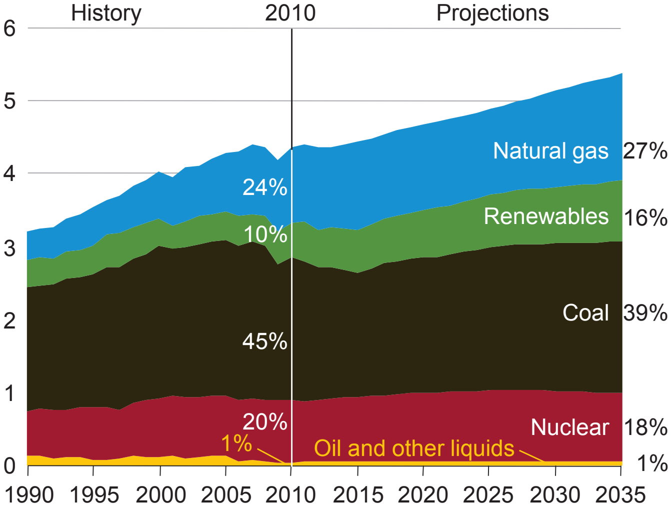
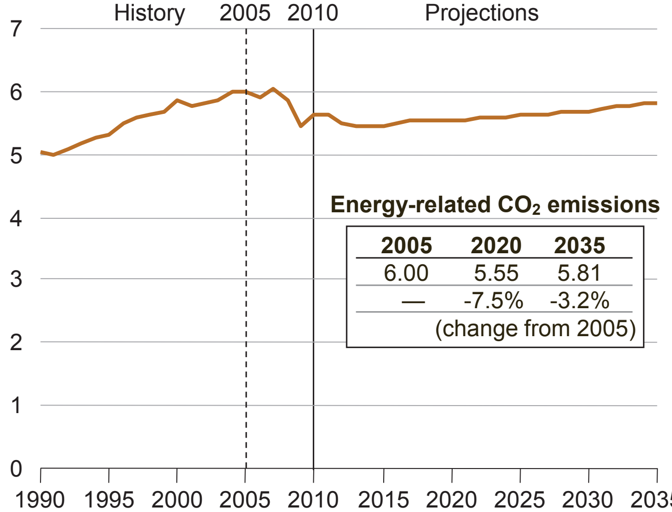


Figure 4. U.S. energy-related carbon dioxide emissions, 1990-2035 (billion metric tons)



To provide a basis against which alternative cases and policies can be compared, the *AEO2012* Reference case generally assumes that current laws and regulations affecting the energy sector remain unchanged throughout the projection (including the implication that laws which include sunset dates do, in fact, become ineffective at the time of those sunset dates). This assumption helps increase the comparability of the Reference case with other analyses, clarifies the relationship of the Reference case to other *AEO2012* cases, and enables policy analysis with less uncertainty arising from speculative legal or regulatory assumptions. Currently, there are many pieces of legislation and regulation that appear to have some probability of being enacted in the not-too-distant future, and some existing laws include sunset provisions that may be extended. However, it is difficult to discern the exact forms that the final provisions of pending legislation or regulations will take, and sunset provisions may or may not be extended. Even in situations where existing legislation contains provisions to allow revision of implementing regulations, those provisions may not be exercised consistently. In certain situations, however, where it is clear that a law or regulation will take effect shortly after the *AEO* Reference case is completed, it may be considered in the projection.

As in past editions of the *AEO,* the complete *AEO2012* will include additional cases, many of which reflect the impacts of extending a variety of current energy programs beyond their current expiration dates and the permanent retention of a broad set of programs that currently are subject to sunset provisions. In addition to the alternative cases prepared for *AEO2012,* EIA has examined proposed policies at the request of Congress over the past few years. Reports describing the results of those analyses are available on EIA's website.[1]

Key updates made for the *AEO2012* Reference case include the following:

- Industrial cogeneration was updated with historical rather than assumed capacity factors for new units and with updated investment decision procedures that reflect regional acceptance rates for new cogeneration facilities.
- A new heavy-duty vehicle model was adopted in the transportation module, with greater detail on size classes and end-use vehicle types to enable modeling of fuel economy regulations covering the heavy-duty vehicle fleet.
- The light-duty fleet model in the transportation module was updated to include a new algorithm for consumer purchase choice that compares fuel savings against incremental vehicle cost for advanced technologies, new technology cost and performance assumptions, and representation of fuel efficiency standards already in effect.
- Shale gas resource estimates for four plays (Haynesville, Fayetteville, Eagle Ford, and Woodford) were updated using the mean value of resource assessments recently released by the U.S. Geological Survey (USGS). The shale gas resource estimate for the Marcellus play was updated using new geologic data from the USGS and recent production data. EIA's estimate of Marcellus resources is substantially below the estimate used for *AEO2011* and falls within the 90-percent confidence range in the August 2011 USGS assessment, although it is higher than the USGS mean value.
- The tight oil resource estimate for the Bakken play was increased to include more of the Three Forks and Sanish zones.
- The handling of U.S. LNG exports of domestically sourced gas was updated, resulting in exports beginning in 2016.
- The electricity module was updated to incorporate the Cross-State Air Pollution Rule (CSAPR)[2] as finalized by the EPA in July 2011. CSAPR requires reductions in emissions from power plants that contribute to ozone and fine particle pollution in 28 States.
- Assumptions regarding the potential for capacity uprates at existing nuclear plants and the timing for existing nuclear plant retirements were revised.
- Updates were made to reflect recent information pertaining to retirement dates for existing power plants and scheduled in-service dates for new power plants.
- California Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006, was incorporated for electricity sector power plants serving California. As modeled, AB 32 imposes a limit on power sector CO_2 emissions, beginning in 2012 and declining at a uniform annual rate through 2020.

Economic growth

Recovery from the 2008-2009 recession is expected to show the slowest growth of any recovery since 1960. Table 2 compares average annual growth rates over a five-year period following U.S. recessions that have occurred since 1960. For the most recent

Table 2. Average annual growth rates over a five-year period following post-1960 recessions[a]

Recession ending	Real GDP	Real consumption	Real investment	Nonfarm employment	Unemployment rate
1975	3.7%	3.2%	7.3%	3.3%	-3.3%
1982	4.5%	4.7%	7.5%	2.6%	-8.6%
1991	3.3%	3.4%	8.5%	2.0%	-4.6%
2009[b]	2.5%	2.1%	9.4%	1.0%	-3.5%

[a]The recessions highlighted in Table 2 are recessions in which the annual GDP percentage change was negative when compared with the previous year's annual value of GDP. The 2001 recession was not included even though it technically qualified as a recession (where two successive quarters showed negative economic growth). The 2001-2002 recession showed a slowdown in annual GDP growth but did not show negative growth.
[b]Average over five-year period following the recession ending in 2009 includes projections for 2011-2014.

[1] See "Congressional Request," website www.eia.gov/analysis/reports.cfm?t=138.
[2]See U.S. Environmental Protection Agency, "Cross-State Air Pollution Rule (CSAPR)," website http://epa.gov/airtransport.

recession, the expected five-year average annual growth rate in real GDP from 2009 to 2014 is 1.3 percentage points below the corresponding average for the three past recessions, with consumption and non-farm employment recovering even more slowly. The slower growth in the early years of the projection has implications for the long term, with a lower economic growth rate leading to a slower recovery in employment and higher unemployment rates. Real GDP in 2035 is 4 percent lower in the *AEO2012* Reference case than was projected in the *AEO2011* Reference case.

Real GDP grows by an average of 2.6 percent per year from 2010 to 2035 in the *AEO2012* Reference case, 0.1 percent per year lower than in the *AEO2011* Reference case. The Nation's population, labor force, and productivity grow at annual rates of 0.9 percent, 0.7 percent, and 1.9 percent, respectively, from 2010 to 2035.

Beyond 2012, the economic assumptions underlying the *AEO2012* Reference case reflect trend projections that do not include short-term fluctuations. Economic growth projections for 2012 are consistent with those published in EIA's October 2011 *Short-Term Energy Outlook*.

Energy prices

Crude oil

Prices for crude oil[3] in 2011 remained generally in a range between $85 and $110 per barrel. In 2011, WTI prices were lower than Brent prices because of pipeline capacity constraints that prevented complete arbitrage between WTI and Brent prices. Real imported sweet crude oil prices (2010 dollars) in the *AEO2012* Reference case rise to $120 per barrel in 2016 (Figure 5) as pipeline capacity from Cushing, Oklahoma, to the Gulf Coast increases, the world economy recovers, and global demand grows more rapidly than the available supplies of liquids from producers outside the Organization of the Petroleum Exporting Countries (OPEC). In 2035, the average real price of crude oil in the Reference case is about $145 per barrel in 2010 dollars, or about $230 per barrel in nominal dollars.

The *AEO2012* Reference case assumes that limitations on access to energy resources restrain the growth of non-OPEC conventional liquids production between 2010 and 2035, and that OPEC targets a relatively constant market share of total world liquids production. Uncertainty regarding OPEC members' actual investment and production decisions and the degree to which non-OPEC countries and countries outside the Organization for Economic Cooperation and Development (OECD) restrict access to potentially productive resources contributes to world oil price uncertainty and the economic viability of unconventional liquids. A wide range of price scenarios and discussion of the significant uncertainty surrounding future world oil prices will be included in the complete *AEO2012* publication released in spring 2012.

The *AEO2012* Reference case also includes significant long-term potential for liquids supply from non-OPEC producers. In several resource-rich regions (including Brazil, Russia, and Kazakhstan), high oil prices, expanded infrastructure, and further investment in exploration and drilling contribute to additional non-OPEC oil production (Figure 6). Also, with the economic viability of Canada's oil sands supported by rising world oil prices and advances in production technology, Canadian oil sands production reaches 5.0 million barrels per day in 2035.

Liquid products

Real prices (in 2010 dollars) for motor gasoline and diesel delivered to the transportation sector in the *AEO2012* Reference case increase from $2.76 and $3.00 per gallon, respectively, in 2010 to $4.09 and $4.49 per gallon in 2035—higher levels than in the *AEO2011* Reference case. Annual average diesel prices are higher than gasoline prices throughout the projection because of stronger global growth in demand for diesel fuel than for motor gasoline.

Figure 5. Average annual world oil prices in three cases, 1980-2035 (real 2010 dollars per barrel)

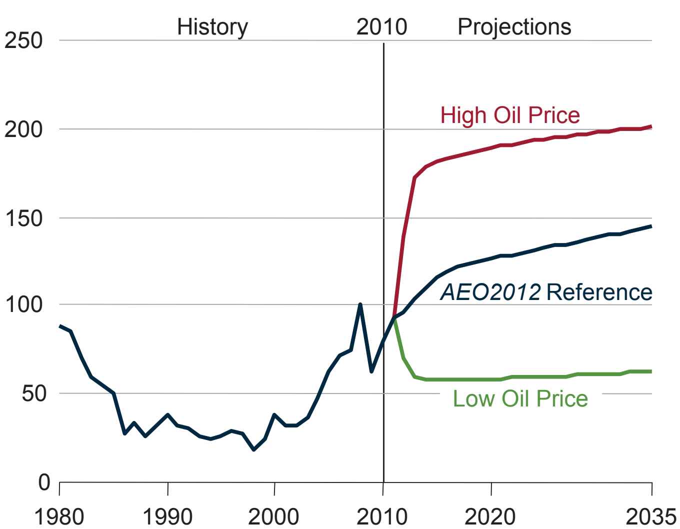
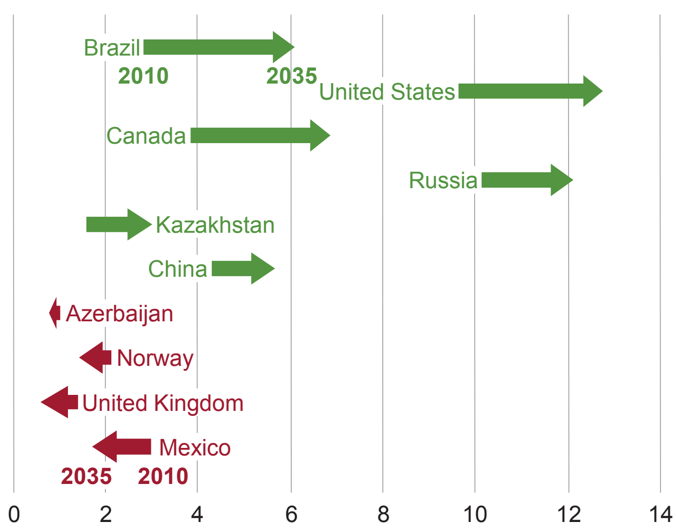


Figure 6. Change in liquids production by top non-OPEC producers, 2010-2035 (million barrels per day)



[3] Light sweet crude oil (West Texas Intermediate [WTI]) traded on NYMEX, which is a member exchange of the CME Group.

Natural gas

With increased production, average annual wellhead prices for natural gas remain below $5 per thousand cubic feet (2010 dollars) through 2023 in the *AEO2012* Reference case. The projected prices reflect continued industry success in tapping the Nation's extensive shale gas resource. The resilience of drilling levels, despite low natural gas prices, is in part a result of high crude oil prices, which significantly improve the economics of natural gas plays that have high concentrations of crude oil, condensates, or natural gas liquids.

After 2023, natural gas prices generally increase as the numbers of tight gas and shale gas wells drilled increase to meet growing domestic demand for natural gas and offset declines in natural gas production from other sources. Natural gas prices rise as production gradually shifts to resources that are less productive and more expensive. Natural gas wellhead prices (in 2010 dollars) reach $6.52 per thousand cubic feet in 2035, compared with $6.48 per thousand cubic feet (2010 dollars) in *AEO2011*.

Coal

The average minemouth price of coal increases by 1.4 percent per year in the *AEO2012* Reference case, from $1.76 per million Btu in 2010 to $2.51 per million Btu in 2035 (2010 dollars). The upward trend of coal prices primarily reflects an expectation that cost savings from technological improvements in coal mining will be outweighed by increases in production costs associated with moving into reserves that are more costly to mine. The coal price outlook in the *AEO2012* Reference case represents a change from the *AEO2011* Reference case, where coal prices were essentially flat.

Electricity

Following the recent rapid decline of natural gas prices, real average delivered electricity prices in the *AEO2012* Reference case fall from 9.8 cents per kilowatthour in 2010 to as low as 9.2 cents per kilowatthour in 2019, as natural gas prices remain relatively low. Electricity prices tend to reflect trends in fuel prices—particularly, natural gas prices, because in much of the country natural gas-fired plants often set wholesale power prices. It can take time, however, for fuel price changes to affect electricity prices because of the varying lengths of fuel- and power-supply contracts and the periods between electricity rate cases.

In the *AEO2012* Reference case, electricity prices are higher throughout the projection than they were in the *AEO2011* Reference case. Although natural gas prices to electricity generators are similar to those in *AEO2011*, the cost of coal is higher. In addition, reliance on natural gas-fired generation in the power sector increases partially as a result of new environmental regulation covering emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X) that make it a more economical option. Electricity prices in 2035 are 9.5 cents per kilowatthour (2010 dollars) in the *AEO2012* Reference case, compared with 9.3 cents per kilowatthour in the *AEO2011* Reference case.

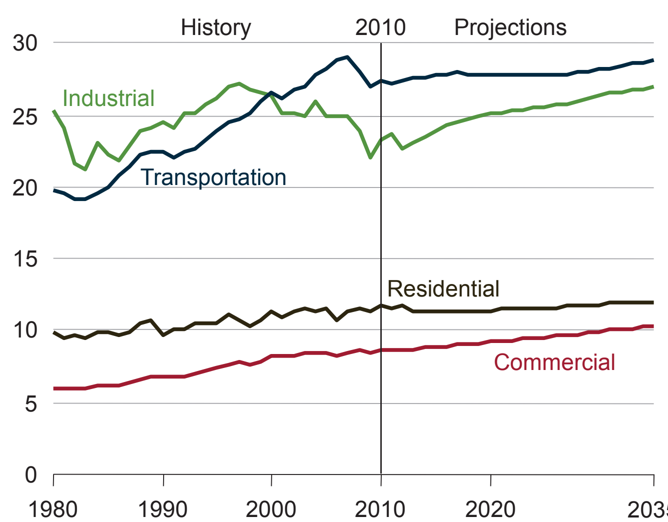
Energy consumption by sector

Transportation

Delivered energy consumption in the transportation sector grows from 27.6 quadrillion Btu in 2010 to 28.8 quadrillion Btu in 2035 in the *AEO2012* Reference case (Figure 7). Energy consumption by light-duty vehicles (LDVs) (including commercial light trucks) initially declines in the Reference case, from 16.5 quadrillion Btu in 2010 to 15.7 quadrillion Btu in 2025, due to projected increases in the fuel economy of highway vehicles. Projected energy consumption for LDVs increases after 2025, to 16.3 quadrillion Btu in 2035. The *AEO2012* Reference case projections do not include proposed increases in LDV fuel economy standards—as outlined in the December 2011 EPA and NHTSA Notice of Proposed Rulemaking for 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards[4]—which would further significantly reduce LDV fuel use if they were incorporated in the projection. The lower projected level of energy consumption in *AEO2012* as compared with *AEO2011* is primarily the result of a reduction in vehicle-miles traveled resulting from the impact of lower projected economic growth and employment rates.

Energy demand for heavy trucks increases from 5.1 quadrillion Btu in 2010 to 6.1 quadrillion Btu in 2035, compared with 6.7 quadrillion Btu in the *AEO2011* Reference

Figure 7. Delivered energy consumption by sector, 1980-2035 (quadrillion Btu)



[4] U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Proposed Rule," *Federal Register*, Vol. 76, No. 231 (December 1, 2011), pp. 74854-75420, website www.gpo.gov/fdsys/pkg/FR-2011-12-01/html/2011-30358.htm.

case. Lower projected industrial output in *AEO2012* leads to slower growth in vehicle-miles traveled by freight trucks, which, in combination with projected increases in fuel economy due to new fuel efficiency and greenhouse gas regulations, leads to lower projected energy demand for heavy vehicles in *AEO2012* as compared with *AEO2011*. The *AEO2012* Reference case includes the fuel efficiency standards for medium- and heavy-duty vehicles published by the EPA and NHTSA in September 2011.[5]

Industrial

Approximately one-third of total U.S. delivered energy, 23.4 quadrillion Btu, was consumed in the industrial sector in 2010. In the *AEO2012* Reference case, total industrial delivered energy consumption grows by 16 percent, from 23.4 quadrillion Btu in 2010 to 27.0 quadrillion Btu in 2035. The largest user of energy is the bulk chemicals industry, which represented 21 percent of total energy consumption in the industrial sector in 2010. By 2026, however, the refining industry, defined as including energy use at petroleum, biofuels, and coal-to-liquids (CTL) facilities, becomes the largest energy-consuming industry in the *AEO2012* Reference case.

Collectively, the energy-intensive manufacturing industries—bulk chemicals, refining, paper products, iron and steel, aluminum, food, glass, and cement—produce slightly more than one-quarter of the total dollar value of industrial shipments while accounting for nearly two-thirds of industrial delivered energy consumption. Although the energy-intensive industries are expected to recover from the recent recession, their long-term growth is slowed by increased international competition and a shift in U.S. manufacturing toward higher value consumer goods. The dollar value of shipments from the energy-intensive manufacturing industries grows by 29 percent from 2010 to 2035 in the *AEO2012* Reference case, while the value of shipments from non-energy-intensive industries increases by 57 percent. As a result of the shift toward non-energy-intensive manufacturing, total industrial delivered energy consumption increases more slowly than total shipments, and the energy intensity of industrial production declines.

Industrial natural gas consumption in the *AEO2012* Reference case is lower than was projected in *AEO2011*, due to revised data for energy intensity in the bulk chemical industry and the adoption of an updated methodology for projecting industrial consumption of combined heat and power (CHP) that better accounts for utilization of both installed and planned capacity. Total industrial natural gas consumption is 8.7 quadrillion Btu in 2035 in the *AEO2012* Reference case, compared with 9.5 quadrillion Btu in the *AEO2011* Reference case.

Residential

Residential delivered energy consumption in the *AEO2012* Reference case grows from 11.7 quadrillion Btu in 2010 to 12.0 quadrillion Btu in 2035. Updated efficiency and cost parameters for major end-use equipment lead to some fuel switching from natural gas and petroleum to electricity in the residential sector due to competitive advantages. In 2035, delivered electricity use totals 5.9 quadrillion Btu and natural gas consumption totals 4.8 quadrillion Btu in the *AEO2012* Reference case, as compared with 5.5 quadrillion Btu and 4.9 quadrillion Btu, respectively, in the *AEO2011* Reference case.

Recent Federal rulemakings for residential equipment—including furnaces, central and room air conditioners, heat pumps, refrigerators, and freezers—were included in the *AEO2011* Reference case based on levels outlined in consensus agreements among efficiency advocates and manufacturers. The final rules have been consistent with levels specified in the consensus agreements.

Commercial

Slower growth in commercial sector activity leads to slower growth in the sector's energy consumption in the *AEO2012* Reference case relative to the *AEO2011* Reference case. Commercial delivered energy consumption grows from 8.7 quadrillion Btu in 2010 to 10.3 quadrillion Btu in 2035. Growth in commercial electricity use averages 1.0 percent per year from 2010 to 2035 in *AEO2012*, comparable to the projected 1.0-percent average annual growth in commercial floorspace. Distributed generation and CHP systems in the commercial sector generate 38 billion kilowatthours of electricity in 2035, 2 percent less than in the *AEO2011* Reference case. Although delivered electricity prices are higher in the *AEO2012* Reference case, slower growth in the commercial sector leads to less opportunity for the adoption of these technologies.

Energy consumption by primary fuel

Total primary energy consumption, which was 101.4 quadrillion Btu in 2007, grows by 10 percent in the *AEO2012* Reference case, from 98.2 quadrillion Btu in 2010 to 108.0 quadrillion Btu in 2035—6 quadrillion Btu less than the *AEO2011* projection for 2035. The fossil fuel share of energy consumption falls from 83 percent of total U.S. energy demand in 2010 to 77 percent in 2035.

Biofuel consumption has been growing and is expected to continue to grow over the projection period. However, the projected increase would present challenges, particularly for volumes of ethanol beyond the saturation level of the E10 gasoline pool. Those additional volumes are likely to be slower in reaching the market, as infrastructure and consumer demand adjust. In the *AEO2012* Reference case, some of the demand for biofuel, which in 2035 is projected to displace more than 600 thousand barrels per day of demand for other liquid fuels, is as a direct replacement for diesel and gasoline.

[5] U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles; Final Rule," *Federal Register*, Vol. 76, No. 179 (September 15, 2011), pp. 57106-57513, website www.gpo.gov/fdsys/pkg/FR-2011-09-15/html/2011-20740.htm.

Total U.S. consumption of liquid fuels, including both fossil fuels and biofuels, grows from 37.2 quadrillion Btu (19.2 million barrels per day) in 2010 to 38.0 quadrillion Btu (20.1 million barrels per day) in 2035 in the *AEO2012* Reference case (Figure 8). As in *AEO2011*, biofuel consumption accounts for most of the growth; with expectations of additional waivers, the biofuel portion of liquid fuels consumption in 2035 is 3.9 quadrillion Btu in *AEO2012*, slightly (0.2 quadrillion Btu) higher than projected in *AEO2011*. The transportation sector dominates demand for liquid fuels, with its share (as measured by energy content) growing slowly from 72 percent of total liquids consumption in 2010 to 73 percent in 2035.

In the *AEO2012* Reference case, natural gas consumption rises from 24.1 trillion cubic feet in 2010 to 26.5 trillion cubic feet in 2035, about the same level as in the *AEO2011* Reference case. The largest share of the growth is for electricity generation. Demand for natural gas in electricity generation grows from 7.4 trillion cubic feet in 2010 to 8.9 trillion cubic feet in 2035. A portion of the growth is attributable to the retirement of 33 gigawatts of coal-fired capacity over the projection period.

Total coal consumption—including the portion of CTL consumed as liquids—increases from 20.8 quadrillion Btu (1,051 million short tons) in 2010 to 22.1 quadrillion Btu (1,155 million short tons) in 2035 in the *AEO2012* Reference case. Coal consumption, mostly for electric power generation, falls off through 2015 as retirements of coal-fired capacity more than offset an increase of about 9 gigawatts in capacity due to come online in 2011 and 2012. After 2015, coal-fired generation increases slowly as the remaining plants are used more intensively. Coal consumption in the electric power sector in 2035 in the *AEO2012* Reference case is about 2.1 quadrillion Btu (98 million short tons) lower than projected in the *AEO2011* Reference case.

Total consumption of marketed renewable fuels grows by 2.8 percent per year in the *AEO2012* Reference case. Growth in consumption of renewable fuels results mainly from the implementation of the Federal renewable fuel standard (RFS) for transportation fuels and State RPS programs for electricity generation. Marketed renewable fuels include wood, municipal waste, biomass, and hydroelectricity in the end-use sectors; hydroelectricity, geothermal, municipal solid waste, biomass, solar, and wind for generation in the electric power sector; and ethanol for gasoline blending and biomass-based diesel in the transportation sector, of which 3.9 quadrillion Btu is included with liquid fuel consumption in 2035. Excluding hydroelectricity, renewable energy consumption in the electric power sector grows from 1.4 quadrillion Btu in 2010 to 3.4 quadrillion Btu in 2035, with biomass accounting for 30 percent of the growth and wind 44 percent. Consumption of solar energy grows the fastest, but starting from a small base it accounts for only a small share of the total in 2035.

Energy intensity

Population is a key determinant of energy consumption through its influence on demand for travel, housing, consumer goods, and services. U.S. energy use per capita was fairly constant over the 1990 to 2007 period, but it began to fall after 2007. In the *AEO2012* Reference case, energy use per capita continues to decline due to the impact of an extended economic recovery and improving energy efficiency. Total U.S. population increases by 25 percent from 2010 to 2035, but energy use grows by only 10 percent, and energy use per capita declines at an annual average rate of 0.5 percent per year from 2010 to 2035 (Figure 9).

From 1990 to 2010, energy use per dollar of GDP declined on average by 1.7 percent per year, in large part because of shifts within the economy from manufactured goods to the service sectors, which use relatively less energy per dollar of GDP. The increase in dollar value that the service sectors add to GDP (in constant dollar terms) was 15 times the corresponding increase for the industrial sector over the same period. As a result, the share of total shipments accounted for by the industrial sector fell from 30 percent in 1991 to 22 percent in 2010. In the *AEO2012* Reference case, the industrial share of total shipments fluctuates in a

Figure 8. U.S. primary energy consumption by fuel, 1980-2035 (quadrillion Btu per year)

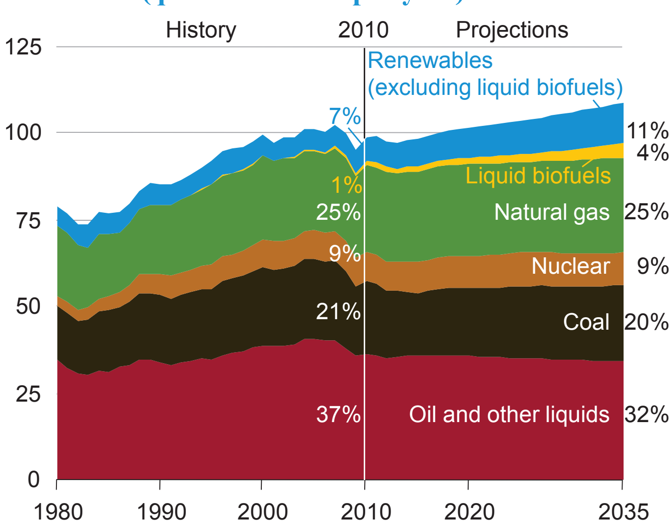
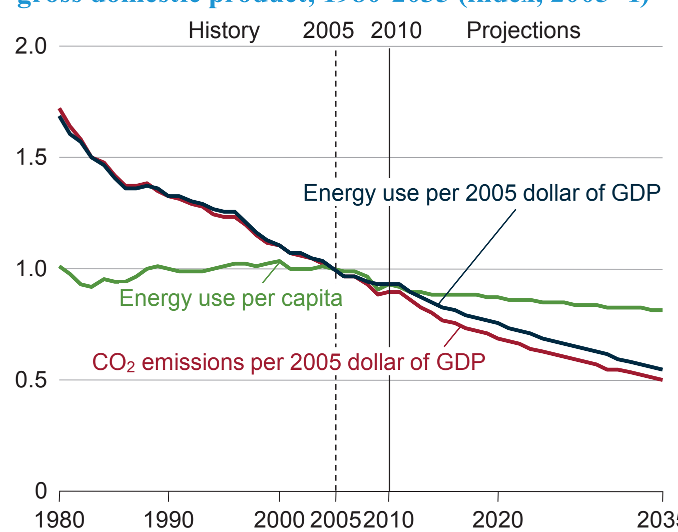


Figure 9. Energy use per capita and per dollar of gross domestic product and emissions per dollar of gross domestic product, 1980-2035 (index, 2005=1)



narrow range between 22.1 and 23.4 percent from 2011 through 2025, then declines slowly to 20.7 percent in 2035 (Figure 10). Energy use per 2005 dollar of GDP declines by 42 percent from 2010 to 2035 in *AEO2012* as the result of a continued shift from manufacturing to services (and, even within manufacturing, to less energy-intensive industries), rising energy prices, and the adoption of policies that promote energy efficiency.

CO_2 emissions per 2005 dollar of GDP have historically tracked closely with energy use per dollar of GDP. In the *AEO2012* Reference case, however, as lower carbon fuels account for a bigger share of total energy use, CO_2 emissions per dollar of GDP decline more rapidly than energy use per dollar of GDP, falling by more than 50% from 2005 to 2035, at an annual rate of 2.3 percent per year.

Energy production and imports

Net imports of energy decline both in absolute terms and as a share of total U.S. energy consumption in the *AEO2012* Reference case (Figure 11). The decline in energy imports reflects increased domestic crude oil and natural gas production, increased use of biofuels (much of which are produced domestically), and demand reductions resulting from the adoption of new efficiency standards and from rising energy prices. The net import share of total U.S. energy consumption in 2035 is 13 percent, compared with 22 percent in 2010. (The share was 29 percent in 2007, but it dropped considerably during the recession.)

Liquids

U.S. production of domestic crude oil in the *AEO2012* Reference case increases from 5.5 million barrels per day in 2010 to 6.7 million barrels per day in 2020, 11 percent higher than in *AEO2011* (Figure 12). Even with a projected decline after 2020, U.S. crude oil production remains above 6.1 million barrels per day through 2035. The higher level of production results mainly from increased onshore oil production, predominantly tight oil. In *AEO2012*, onshore tight oil production accounts for 31 percent of lower 48 onshore oil production in 2035, compared with 12 percent in 2010. As with shale gas, the application of recent technology advances significantly increases the development of tight oil resources. Offshore crude oil production in the Gulf of Mexico trends upward over time, fluctuating between 1.4 and 2.0 million barrels per day, as new large development projects are started. Alaska's oil production decline is slowed by the development of offshore projects.

The faster growth in tight oil production in *AEO2012* offsets slower growth in enhanced oil recovery (EOR) production, as the economics of tight oil plays are more favorable than the economics of CO_2-EOR projects. In addition, the quantity of CO_2 available in 2035 from planned CTL plants necessary for CO_2-EOR production is 52 percent lower in *AEO2012* than was projected in *AEO2011*, due to a reduction in the number of CTL projects expected in *AEO2012*.

Figure 10. Outputs from the industrial and service sectors, 1990-2035 (trillion 2005 dollars)

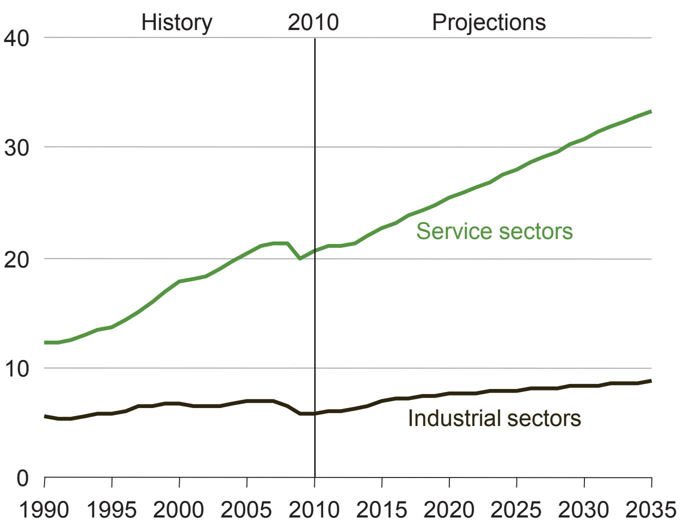


Figure 11. Total energy production and consumption, 1980-2035 (quadrillion Btu)

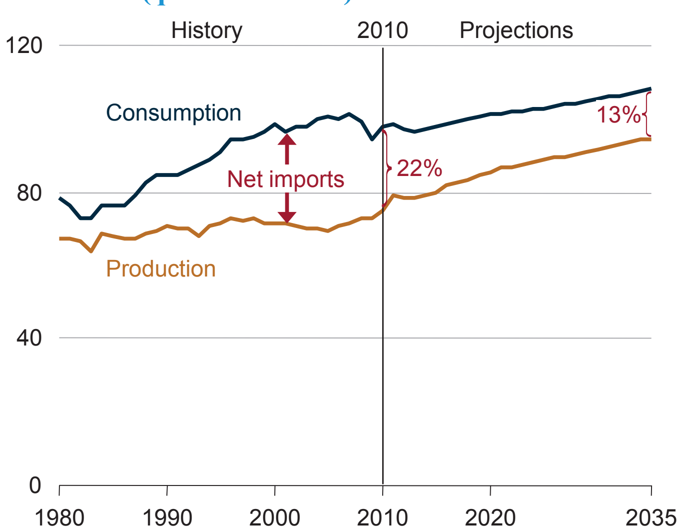
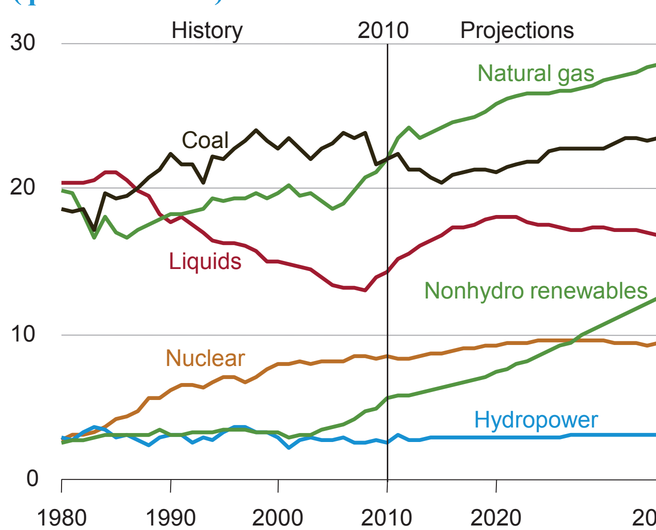


Figure 12. Energy production by fuel, 1980-2035 (quadrillion Btu)



Consequently, CO_2-EOR in *AEO2012* accounts for 11 percent of cumulative lower 48 onshore oil production from 2010 to 2035, as compared with 21 percent in *AEO2011*.

U.S. dependence on imported liquid fuels continues to decline in *AEO2012*, primarily as a result of increased domestic oil production, increased production of biofuels driven by the EISA2007 RFS, and lower demand for transportation fuels in *AEO2012* compared with *AEO2011*. Imported liquid fuels as a share of total U.S. liquid fuel use reached 60 percent in 2005 and 2006 before falling to 50 percent in 2010, and the percentage continues to decline over the projection period in *AEO2012*, to 37 percent in 2035—significantly lower than the 42-percent share in *AEO2011*.

Although liquids production from many sources is higher in *AEO2012* than was projected in the *AEO2011* Reference case, production of advanced cellulosic biofuels is lower. Over the past three consecutive years, production goals for cellulosic ethanol in the EISA2007 RFS have not been achieved. While EIA has projected a need for waivers in all Reference case projections since the passage of the EISA2007 RFS, EIA's view of technology development and market penetration rates for cellulosic biofuel technologies has grown somewhat more pessimistic in *AEO2012*.

Natural gas

Cumulative natural gas production from 2010 through 2035 in the *AEO2012* Reference case is 7 percent higher than in *AEO2011*, even though the estimated natural gas resource base is lower. This primarily reflects increased shale gas production resulting from the application of recent technological advances, as well as continued drilling in shale plays with high concentrations of natural gas liquids and crude oil, which have a higher value in energy equivalent terms than dry natural gas. Production levels for tight gas and coalbed methane exceed those in the *AEO2011* Reference case through 2035, making significant contributions to the overall increase in production. Offshore natural gas production in the Gulf of Mexico fluctuates between 2.0 and 2.8 trillion cubic feet per year as new large projects directed toward liquids development are started over time.

In the *AEO2012* Reference case, the estimated unproved technically recoverable resource (TRR) of shale gas for the United States is 482 trillion cubic feet, substantially below the estimate of 827 trillion cubic feet in *AEO2011*. The decline largely reflects a decrease in the estimate for the Marcellus shale, from 410 trillion cubic feet to 141 trillion cubic feet. Both EIA and USGS have recently made significant revisions to their TRR estimates for the Marcellus shale. Drilling in the Marcellus accelerated rapidly in 2010 and 2011, so that there is far more information available today than a year ago. Indeed, the daily rate of Marcellus production doubled during 2011 alone. Using data though 2010, USGS updated its TRR estimate for the Marcellus to 84 trillion cubic feet, with a 90-percent confidence range from 43 to 144 trillion cubic feet—a substantial increase over the previous USGS estimate of 2 trillion cubic feet dating from 2002. For *AEO2012*, EIA uses more recent drilling and production data available through 2011 and excludes production experience from the pre-shale era (before 2008). EIA's TRR estimate for the entire Northeast also includes TRR of 16 trillion cubic feet for the Utica shale, which underlies the Marcellus and is still relatively little explored. The complete *AEO2012* publication will include a more in-depth examination of the factors that affect resource estimates.

In the *AEO2012* Reference case, the United States becomes a net exporter of LNG starting in 2016 and an overall net exporter of natural gas in 2021. U.S. LNG exports are assumed to start with a capacity of 1.1 billion cubic feet per day in 2016 and increase by an additional 1.1 billion cubic feet per day in 2019. Over the projection period, cumulative net pipeline imports of natural gas from Canada and Mexico in the *AEO2012* Reference case are less than 50 percent of those projected in the *AEO2011* Reference case, with the United States becoming a net pipeline exporter of natural gas in 2025. In the *AEO2012* Reference case, net pipeline imports from Canada fall by 62 percent over the projection period, and net pipeline exports to Mexico grow by 440 percent. Cumulative U.S. LNG imports from 2011 through 2035 are down by 20 percent in *AEO2012* compared with *AEO2011*, due in part to increased use of LNG in markets outside North America, strong domestic production, and relatively low U.S. natural gas prices in comparison with other global markets. As in the *AEO2011* Reference case, the Alaska natural gas pipeline is not constructed in the *AEO2012* Reference case, because assumed high capital costs and low natural gas wellhead prices make it uneconomical to proceed with the pipeline project over the projection period.

Coal

Although coal remains the leading fuel for U.S. electricity generation, its share of total generation is lower in the *AEO2012* Reference case than was projected in the *AEO2011* Reference case. As a consequence, while still growing in most projection years after 2015, total coal production is lower in the *AEO2012* Reference case than in the *AEO2011* Reference case, with the gap between the two outlooks increasing substantially over the period from 2020 to 2035.

In the *AEO2012* Reference case, domestic coal production increases at an average rate of 0.3 percent per year, from 22.1 quadrillion Btu (1,084 million short tons) in 2010 to 23.5 quadrillion Btu (1,188 million short tons) in 2035. Mines in the West account for nearly all the projected increase in overall production, although even Western coal production is expected to decline somewhat between 2010 and 2015 as low natural gas prices and the retirement of a sizable amount of coal-fired generating capacity leads to a decline in overall coal consumption in the electricity sector. On a Btu basis, the share of domestic coal production originating from mines in the West increases from 47 percent in 2010 to 56 percent in 2035, and the Appalachian share declines from 39 percent to 29 percent during the same period, with most of the decline occurring by 2020. In the Interior region, coal production remains relatively stable over the projection period, with production in 2035 higher than in 2010.

Electricity generation currently accounts for 93 percent of total U.S. coal consumption. In the *AEO2012* Reference case, projected coal consumption in the electric power sector in 2035 (19.6 quadrillion Btu) is about 2 quadrillion Btu less than in the *AEO2011* Reference case (21.6 quadrillion Btu). For the most part, the reduced outlook for coal consumption in the electricity sector is the result of lower natural gas prices and higher coal prices that, taken together, support increased generation from natural gas in the *AEO2012* Reference case. More generation from nonhydroelectric renewables and slightly lower overall demand for electricity, particularly in regions that rely heavily on coal-fired generation, also contribute to the reduced outlook for electricity sector coal consumption in the *AEO2012* Reference case. With a more robust outlook for coal imports by Asian countries, *AEO2012* shows higher coal exports than *AEO2011*.

Electricity generation

Total electricity consumption, including both purchases from electric power producers and on-site generation, grows from 3,879 billion kilowatthours in 2010 to 4,775 billion kilowatthours in 2035 in the *AEO2012* Reference case, increasing at an average annual rate of 0.8 percent, about the same rate as in the *AEO2011* Reference case.

The combination of slow growth in electricity demand, competitively priced natural gas, programs encouraging renewable fuel use, and the implementation of new environmental rules dampens coal use in the future. The *AEO2012* Reference case includes the impacts of the CSAPR, which was finalized in July 2011 and was not represented in the *AEO2011* Reference case. CSAPR requires reductions in SO_2 and NO_X emissions in roughly one-half of the States, with an initial target in 2012 and further reductions in 2014. Even so, coal remains the dominant energy source for electricity generation, but its share of total generation declines from 45 percent in 2010 to 39 percent in 2035 (see Figure 3 on page 2). Market concerns about GHG emissions continue to slow the expansion of coal-fired capacity in the *AEO2012* Reference case, even under current laws and policies. Low projected fuel prices for new natural gas-fired plants also affect the relative economics of coal-fired capacity, as does the continued rise in construction costs for new coal-fired power plants. As retirements outpace new additions, total coal-fired generating capacity falls from 318 gigawatts in 2010 to 301 gigawatts in 2035 in the *AEO2012* Reference case.

Electricity generation using natural gas is higher in the *AEO2012* Reference case than was projected in the *AEO2011* Reference case, particularly over the next 10 years, during which natural gas prices are expected to remain low. New natural gas-fired plants also are much cheaper to build than new renewable or nuclear plants. In 2015, natural gas-fired generation in *AEO2012* is 13 percent higher than in *AEO2011*, and in 2035 it is still 6 percent higher.

Electricity generation from nuclear power plants grows by 11 percent in the *AEO2012* Reference case, from 807 billion kilowatthours in 2010 to 894 billion kilowatthours in 2035, accounting for about 18 percent of total generation in 2035 (compared with 20 percent in 2010). Nuclear generating capacity increases from 101 gigawatts in 2010 to a high of 115 gigawatts in 2025, after which a few retirements result in a decline to 112 gigawatts in 2035. *AEO2012* incorporates new information about planned nuclear plant construction, as well as an updated estimate of the potential for capacity uprates at existing units. A total of 10 gigawatts of new nuclear capacity is projected through 2035, as well as an increase of 7 gigawatts achieved from uprates to existing nuclear units. About 6 gigawatts of existing nuclear capacity is retired, primarily in the last few years of the projection, as not all owners of existing nuclear capacity apply for and receive license renewals to operate their plants beyond 60 years.

Increased generation from renewable energy in the electric power sector, excluding hydropower, accounts for 33 percent of the overall growth in electricity generation from 2010 to 2035. Generation from renewable resources grows in response to Federal tax credits, State-level policies, and Federal requirements to use more biomass-based transportation fuels, some of which can produce electricity as a byproduct of the production process. Near-term market growth in some sectors, such as solar energy, is projected to result in significantly reduced costs in the *AEO2012* Reference case, increasing the projected growth for those resources as compared with the *AEO2011* projections. More retirements of coal-fired capacity are expected in the *AEO2012* Reference case than were projected in *AEO2011* because of slower growth in electricity demand, continued competition from natural gas and renewable plants, and the need to comply with new environmental regulations. Growth in renewable generation is supported by many State requirements, as well as new regulations on CO_2 emissions in California. The share of U.S. electricity generation coming from renewable fuels (including conventional hydropower) grows from 10 percent in 2010 to 16 percent in 2035. In the *AEO2012* Reference case, Federal subsidies for renewable generation are assumed to expire as enacted. Extensions of such subsidies could have a large impact on renewable generation.

Energy-related CO_2 emissions

Although total U.S. energy-related CO_2 emissions increased by almost 4 percent in 2010, they do not return to their 2005 level (5,996 million metric tons) by the end of the *AEO2012* projection period (see Figure 4 on page 2). Emissions per capita fall by an average of 1 percent per year from 2005 to 2035, as growth in demand for transportation fuels is moderated by higher energy prices and Federal CAFE standards. In addition, electricity-related emissions are tempered by efficiency standards, State RPS requirements, and implementation of the CSAPR, which helps shift the fuel mix away from coal toward lower carbon fuels.

Energy-related CO_2 emissions reflect the mix of fossil fuels consumed. Given the high carbon content of coal and its use to generate 45 percent of the U.S. electricity supply in 2010, prospects for CO_2 emissions depend, in part, on growth in electricity demand as well as the portion of that demand satisfied by coal-fired generation. After declining from 2007 to 2009, electricity sales grew in 2010 by 4.3 percent. Electricity sales continue to grow through 2035 in the *AEO2012* Reference case, but the growth is tempered by a variety of regulatory and socioeconomic factors, including appliance and building efficiency standards and a continued transition to a more service-oriented economy. The combination of slow demand growth, competitive natural gas prices, and CSAPR included in the *AEO2012* Reference case lowers the consumption of coal within the first 5 years of the projection period; as a result, emissions from coal combustion in the power sector in 2015 are 149 million metric tons below the *AEO2011* Reference case projection. With modest growth in electricity demand and increased use of renewables for electricity generation, electricity-related CO_2 emissions grow by a total of 4.9 percent (0.2 percent per year) from 2010 to 2035. Growth in CO_2 emissions from transportation activity also slows in comparison with the recent pre-recession experience, as Federal CAFE standards increase the efficiency of the vehicle fleet, employment recovers slowly, and higher fuel prices moderate growth in travel. The *AEO2012* Reference case projections do not include proposed increases in fuel economy standards for model years 2017 through 2025, which are expected to further reduce fuel use and emissions.

Taken together, these factors tend to slow the growth in primary energy consumption and CO_2 emissions. As a result, energy-related CO_2 emissions in 2035 are only 3 percent higher than in 2010 (as compared with the 10-percent increase in total energy use), and the carbon intensity of U.S. energy consumption falls from 57.4 to 53.8 kilograms per million Btu (6.3 percent). Over the same period, U.S. economic activity becomes less carbon-intensive, as energy-related CO_2 emissions per dollar of GDP decline by 45 percent.

List of Acronyms

AB 32	Global Warming Solutions Act of 2006
AEO	*Annual Energy Outlook*
AEO2011	*Annual Energy Outlook 2011*
AEO2012	*Annual Energy Outlook 2012*
Btu	British thermal units
CAFE	Corporate average fuel economy
CHP	Combined heat and power
CO_2	Carbon dioxide
CTL	Coal-to-liquids
CSAPR	Cross-State Air Pollution Rule
EIA	U.S. Energy Information Administration
EISA2007	Energy Independence and Security Act of 2007
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
GDP	Gross domestic product
LDVs	Light-duty vehicles
LNG	Liquefied natural gas
NGL	Natural gas liquids
NHTSA	National Highway Traffic Safety Administration
NO_X	Nitrogen oxides
OCS	Outer Continental Shelf
OECD	Organization for Economic Cooperation and Development
OPEC	Organization of the Petroleum Exporting Countries
RFS	Renewable fuel standard
RPS	Renewable portfolio standard
SO_2	Sulfur dioxide
TRR	Technically recoverable resource
USGS	United States Geological Survey

Table 1. Comparison of projections in the *AEO2012* and *AEO2011* Reference cases, 2009-2035

			2025		2035	
Energy and economic factors	2009	2010	*AEO2012*	*AEO2011*	*AEO2012*	*AEO2011*
Primary energy production (quadrillion Btu)						
Petroleum	13.93	14.37	17.48	16.19	16.81	16.72
Dry natural gas	21.09	22.10	26.63	24.60	28.51	27.00
Coal	21.63	22.08	22.51	23.64	23.51	26.01
Nuclear power	8.36	8.44	9.60	9.17	9.35	9.14
Hydropower	2.67	2.51	2.97	3.04	3.06	3.09
Biomass	3.72	4.05	6.73	7.20	9.68	8.63
Other renewable energy	1.11	1.34	2.13	2.58	2.80	3.22
Other	0.47	0.64	0.76	0.88	0.88	0.78
Total	**72.97**	**75.52**	**88.79**	**87.29**	**94.59**	**94.59**
Net imports (quadrillion Btu)						
Liquid fuels[a]	20.90	20.35	16.33	19.91	16.22	19.85
Natural gas	2.76	2.66	-0.81	1.14	-1.39	0.23
Coal/other (- indicates export)	-0.90	-1.58	-1.44	-0.51	-1.29	-0.50
Total	**22.77**	**21.43**	**14.08**	**20.54**	**13.54**	**19.58**
Consumption (quadrillion Btu)						
Liquid fuels[a]	36.49	37.25	37.04	39.84	38.00	41.70
Natural gas	23.42	24.71	25.80	25.73	27.11	27.24
Coal	19.62	20.76	20.60	22.61	21.57	24.30
Nuclear power	8.36	8.44	9.60	9.17	9.35	9.14
Hydropower	2.67	2.51	2.97	3.04	3.06	3.09
Biomass	2.72	2.88	4.52	4.71	5.85	5.25
Other renewable energy	1.11	1.34	2.13	2.58	2.80	3.22
Net electricity imports	0.32	0.29	0.28	0.27	0.24	0.25
Total	**94.70**	**98.16**	**102.93**	**107.95**	**107.97**	**114.19**
Liquid fuels (million barrels per day)						
Domestic crude oil production	5.36	5.47	6.42	5.88	6.12	5.95
Other domestic production	3.66	4.22	5.71	5.84	6.66	6.84
Net imports	9.72	9.53	7.39	9.22	7.36	9.14
Consumption	18.81	19.17	19.46	20.99	20.08	21.93
Natural gas (trillion cubic feet)						
Dry gas production + supplemental	20.65	21.65	26.07	24.04	27.90	26.38
Net imports	2.68	2.58	-0.84	1.08	-1.43	0.18
Consumption	22.85	24.13	25.20	25.07	26.48	26.55
Coal (million short tons)						
Production	1,089	1,098	1,144	1,202	1,204	1,333
Net imports	-38	-64	-57	-19	-49	-18
Consumption	997	1,051	1,087	1,182	1,155	1,315

Table 1. Comparison of projections in the *AEO2012* and *AEO2011* Reference cases, 2009-2035 (continued)

			2025		2035	
Energy and economic factors	2009	2010	*AEO2012*	*AEO2011*	*AEO2012*	*AEO2011*
Prices (2010 dollars)						
Imported low-sulfur, light crude oil (dollars per barrel)	62.37	79.39	132.50	118.57	144.56	126.03
Imported crude oil (dollars per barrel)	59.72	75.87	121.23	108.34	132.69	114.69
Domestic natural gas at wellhead (dollars per thousand cubic feet)	3.85	4.16	5.23	5.47	6.52	6.48
Domestic coal at minemouth (dollars per short ton)	33.62	35.61	43.87	33.51	49.24	34.22
Average electricity price (cents per kilowatthour)	9.9	9.8	9.3	9.0	9.5	9.3
Economic indicators						
Real gross domestic product (billion 2005 dollars)	12,703	13,088	19,176	20,020	24,639	25,692
GDP chain-type price index (2005 = 1.000)	1.097	1.110	1.459	1.450	1.762	1.749
Real disposable personal income (billion 2005 dollars)	9,883	10,062	14,474	15,118	18,252	19,224
Value of manufacturing shipments (billion 2005 dollars)	4,052	4,260	5,735	6,016	6,270	6,770
Primary energy intensity (thousand Btu per 2005 dollar of GDP)	7.45	7.50	5.37	5.39	4.38	4.44
Carbon dioxide emissions (million metric tons)	5,425	5,634	5,618	5,938	5,806	6,311

[a]Includes petroleum-derived fuels and non-petroleum-derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel.
Notes: Quantities reported in quadrillion Btu are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity. Both coal consumption and coal production include waste coal consumed in the electric power and industrial sectors.
Sources: AEO2012 National Energy Modeling System, run REF2012.D121011B; and AEO2011 National Energy Modeling System, run REF2011.D020911A.

Table A13. Natural gas supply, disposition, and prices
(trillion cubic feet per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Production								
Dry gas production[1]	20.58	21.58	23.67	25.21	26.00	26.79	27.84	1.0%
Supplemental natural gas[2]	0.07	0.07	0.06	0.06	0.06	0.06	0.06	-0.2%
Net imports	**2.68**	**2.58**	**1.70**	**0.29**	**-0.84**	**-0.97**	**-1.43**	**- -**
Pipeline[3]	2.26	2.21	1.54	1.04	-0.10	-0.26	-0.68	- -
Liquefied natural gas[4]	0.42	0.37	0.16	-0.74	-0.74	-0.71	-0.74	- -
Total supply	**23.32**	**24.22**	**25.43**	**25.56**	**25.22**	**25.88**	**26.48**	**0.4%**
Consumption by sector								
Residential	4.78	4.94	4.87	4.82	4.76	4.72	4.65	-0.2%
Commercial	3.12	3.21	3.33	3.40	3.42	3.49	3.56	0.4%
Industrial[5]	6.17	6.60	6.97	7.23	7.12	7.00	7.00	0.2%
Natural-gas-to-liquids heat and power[6]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural gas to liquids production[7]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electric power[8]	6.87	7.38	8.09	7.89	7.69	8.40	8.93	0.8%
Transportation[9]	0.04	0.04	0.06	0.08	0.11	0.14	0.16	5.9%
Pipeline fuel	0.60	0.63	0.67	0.67	0.66	0.66	0.66	0.2%
Lease and plant fuel[10]	1.28	1.34	1.39	1.43	1.44	1.46	1.50	0.5%
Total	**22.85**	**24.13**	**25.38**	**25.52**	**25.20**	**25.87**	**26.48**	**0.4%**
Discrepancy[11]	**0.47**	**0.09**	**0.05**	**0.04**	**0.03**	**0.01**	**-0.00**	**- -**
Natural gas prices								
(2010 dollars per million Btu)								
Henry hub spot price	4.00	4.39	4.27	4.80	5.75	6.19	7.23	2.0%
Average lower 48 wellhead price[12]	3.75	4.06	3.83	4.28	5.10	5.48	6.36	1.8%
(2010 dollars per thousand cubic feet)								
Average lower 48 wellhead price[12]	3.85	4.16	3.92	4.38	5.23	5.61	6.52	1.8%
Delivered prices								
(2010 dollars per thousand cubic feet)								
Residential	12.25	11.36	10.54	11.33	12.41	12.98	14.21	0.9%
Commercial	10.06	9.32	8.81	9.44	10.38	10.79	11.84	1.0%
Industrial[5]	5.47	5.65	4.97	5.44	6.27	6.64	7.59	1.2%
Electric power[8]	4.97	5.25	4.64	5.02	5.83	6.27	7.24	1.3%
Transportation[13]	14.49	13.54	12.69	13.01	13.66	13.91	14.75	0.3%
Average[14]	**7.55**	**7.33**	**6.58**	**7.12**	**8.03**	**8.42**	**9.40**	**1.0%**

Table A13. Natural gas supply, disposition, and prices (continued)
(trillion cubic feet per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Natural gas prices								
(nominal dollars per million Btu)								
Henry hub spot price	3.95	4.39	4.61	5.70	7.56	8.98	11.48	3.9%
Average lower 48 wellhead price[12]	3.71	4.06	4.13	5.09	6.71	7.94	10.10	3.7%
(nominal dollars per thousand cubic feet)								
Average lower 48 wellhead price[12]	3.80	4.16	4.23	5.21	6.87	8.13	10.34	3.7%
Delivered prices								
(nominal dollars per thousand cubic feet)								
Residential	12.11	11.36	11.36	13.47	16.31	18.81	22.55	2.8%
Commercial	9.95	9.32	9.49	11.22	13.64	15.64	18.79	2.8%
Industrial[5]	5.40	5.65	5.36	6.46	8.25	9.62	12.05	3.1%
Electric power[8]	4.92	5.25	5.00	5.96	7.66	9.08	11.49	3.2%
Transportation[13]	14.32	13.54	13.68	15.46	17.95	20.16	23.41	2.2%
Average[14]	**7.46**	**7.33**	**7.10**	**8.46**	**10.56**	**12.20**	**14.92**	**2.9%**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida, as well as gas from Canada and Mexico.
[4]Includes natural gas used for liquefaction at export terminals.
[5]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[6]Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
[7]Includes any natural gas that is converted into liquid fuel.
[8]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[9]Compressed natural gas used as vehicle fuel.
[10]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[11]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2009 and 2010 values include net storage injections.
[12]Represents lower 48 onshore and offshore supplies.
[13]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[14]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 supply values; and lease, plant, and pipeline fuel consumption: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2010 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). Other 2009 and 2010 consumption based on: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 wellhead price: U.S. Department of the Interior, Office of Natural Resources Revenue; and EIA, *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2009 residential and commercial delivered prices: EIA, *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2010 residential and commercial delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2009 and 2010 electric power prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2010 and April 2011, Table 4.2, and EIA, *State Energy Data Report 2009*, DOE/EIA-0214(2009) (Washington, DC, June 2011). 2009 and 2010 industrial delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010) and the *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2009 transportation sector delivered prices are based on: EIA, *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010) and estimated state taxes, federal taxes, and dispensing costs or charges. 2010 transportation sector delivered prices are model results. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D121011B.