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RE: Comments on the informal draft of the Mine Methane Capture (MMC) Projects Compliance Offset Protocol released 31 January 2014

Dear Ms. Sahota, Dr. Mayeur, and Ms. Bede,

Thank you once again for the opportunity to provide input on the design of the proposed Mine Methane Capture Protocol.

We sincerely appreciate two clarifications included in the informal draft that we believe will substantially strengthen the additionality of projects eligible for crediting under the MMC protocol. First, we thank you for clarifying in section 2.4(b) that abandoned mines that injected methane into a pipeline while active are not eligible to generate credits from pipeline injection once abandoned. This practice is very common – we understand that every mine abandoned since 1996 that had injected methane into a pipeline when active has continued to do so once abandoned. This restriction thus avoids the potential generation of a large quantity of non-additional credits from the abandoned mine portion of the Protocol (reductions that would not be caused by the Protocol and would have happened anyway), while maintaining eligibility for truly additional projects at abandoned mines. We believe this clarification will substantially strengthen the final Protocol. We provide further support for this exclusion in Section 4 below.

Second, we support the clarification that the Legal Requirement Test for additionality must be met throughout the life of the project, and not just at the time of project listing (section 3.4.1(a)). This change avoids another potential source of non-additional credits. Again, we believe that this change will substantially strengthen the final version of the Protocol.

We continue to believe that there are additional opportunities to strengthen the Protocol. Our first three recommendations, listed below, involve excluding certain sub-sets of projects from participating in the Protocol to avoid specific adverse effects from the incentives the Protocol would otherwise create. We believe that the exclusion of these sub-sets of project types would not in any way diminish the policy-effectiveness of the Protocol as a compliance instrument under the cap-and-trade program. These three recommendations focus on drainage methane from active underground mines. Our recommendations are:

(1) Drainage methane from new mines and major mine expansions with releases large enough to require Prevention of Significant Deterioration (PSD) permits should be ineligible for crediting in order to avoid conflicts with Clean Air Act implementation.
So long as Environmental Protection Agency (EPA) guidance on PSD permitting for mines is followed by state permitting authorities requiring PSD permits, methane capture from drainage wells would be required at the large majority of permit-requiring mines. Yet, the current draft MMC Protocol risks undercutting this EPA guidance on PSD permitting by creating incentives for state permitting authorities to refrain from requiring methane capture so that mines within their jurisdictions would be eligible to participate in the Protocol and to receive the large revenues expected from large MMC projects. To avoid this potential adverse effect and the resulting increases in emissions, we recommend that the Board amend the Protocol so that the destruction of methane from any new drainage wells at a mine requiring a PSD permit be ineligible for crediting under the Protocol. Restricting this eligibility eliminates the incentive for state permitting authorities to weaken PSD permit requirements for greenhouse gases (GHGs), and would avoid any conflict with EPA's regulation of greenhouse gases. Importantly, it would accomplish this without any disadvantage, since the only mines that would be prevented from participating in the Protocol due to this change would be mines that should be required to capture methane under the PSD permitting process.

(2) In order to avoid increasing mine profits by amounts large enough to extend the lives of some mines, the Board should consider eliminating eligibility of drainage methane flaring at active mines or placing a fee on credits generated by this project type.
Such a change would also create greater incentive for mines to capture drainage methane for productive use rather than for flaring. **We also suggest that the Board commit to monitoring the offset profits earned from drainage methane and ventilation air methane (VAM) capture projects as offset prices change and as experience is gained with these technologies. We suggest that the Board include provisions for a response if, in fact, profits become large enough to extend mine operation.**

(3) Furthermore, incentives for mines to flare methane that would otherwise have been injected into a pipeline is a second reason to specifically eliminate eligibility of drainage methane flaring at new underground mines.
Allowing offset credits from the flaring of drainage methane is of particular concern at new mines. At recent natural gas and offset credit prices a mine operator could earn more income from selling offset credits than from selling natural gas. While the Protocol largely prevents mines that already inject drainage methane into a pipeline from switching to flaring to sell offset credits, this protection does not extend to new mines. A mine operator could list a flaring project under the Protocol even if they would have chosen to inject that methane into a pipeline absent the incentive created by the Protocol.

(4) The Board should clarify in its additionality assessment of mine methane capture at abandoned mines (section 3.4.2(b)(4)) that methane capture by pipeline injection systems installed when mines were active is either common practice or is excluded from the evaluation in this section.

We recommend the following changes:

3.4.2(b)

(4) Abandoned Mine Methane Recovery Activities

(A) Destruction of extracted mine methane via any end-use management option other than injection into a natural gas pipeline for off-site consumption with a pipeline injection system installed when the mine was active automatically meets the performance standard evaluation because it is not common practice nor considered business-as-usual, and is therefore eligible for crediting under this protocol.

(B) Pipeline injection of mine methane at abandoned mines that injected drainage methane into a natural gas pipeline for off-site consumption when the mine was active is common practice and considered business-as-usual, and therefore ineligible for crediting under this protocol.

(5) We recommend the following clarification: The Protocol's definition of "non-qualifying destruction device" as "a destruction device that is. . . operational at the mine prior to offset project commencement. . ." is meaningless because "offset project commencement is *defined* as the date at which the offset project's mine methane capture and destruction equipment becomes operational." (section 3.6). In resolving this language, the Board should make sure the following provisions are preserved:

1. Devices that were installed prior to the date of project listing, or more than one year prior to project listing, should be considered ineligible for crediting, and
2. Any active underground mine that injected drainage methane into a pipeline should not be able to do so as an offset project after abandonment.

Below we recommend specific changes to the Protocol language that we believe reflect the Board's intention and preserve these two provisions.

We describe each of these recommendations in detail below. In addition, we include our previous comment letters to the Board on the MMC protocol for reference as an attachment.

1. **Drainage methane from new mines and major mine expansions with releases large enough to require Prevention of Significant Deterioration (PSD) permits should be ineligible for crediting in order to avoid conflicts with Clean Air Act implementation.**

We remain concerned about the eligibility of drainage methane capture from new active underground mines and major mine expansions with emissions releases large enough to trigger PSD permitting requirements. Under the Clean Air Act Tailoring Rule, PSD permits are required for emissions increases over 75,000 tCO_2e/year for major modifications of existing mines or 100,000 tCO_2e/year for new mines. In past comments we discussed a perverse incentive expected to result from allowing drainage methane from all new mines and major mine modifications to earn credits under the Protocol (see section 2 of our attached comment to the Board from 23 October 2013). As you know, PSD permitting requirements are determined on a case-by-case basis by state-level agencies. For each permit application, the state agency granting the permit must determine if methane capture is Best Available Control Technology (BACT) for reducing emissions for that particular mine and would therefore be required as a part of the construction permit. We discussed our concern that the Protocol may encourage state agencies to make weak BACT determinations so that mines in their state would be eligible under California's MMC Protocol to be paid to capture methane instead of being required to do so as a PSD permit condition. To the extent that BACT determinations are weakened in this way, not only would non-additional credits be generated from projects that would otherwise have been required by law, but these permits would also serve as precedent for other PSD applications in the state and via EPA's RACT/BACT/LAER Clearinghouse (RBLC) at the national level.[1] The precedent that could result from early and weak BACT rulings is of particular concern because state agencies commonly base new BACT determinations on past determinations at comparable facilities.[2] Given the substantial profits that could be earned from MMC at the gassiest mines (see Section 2 below), mine owners can be expected to watch state-level BACT determinations closely.

In these comments we stress and elaborate on three points. First, we emphasize that mines with emissions greater than 75,000 tons CO_2e/y for existing sources that undertake major modifications and 100,000 tons CO_2e/y for new sources are currently required to apply for PSD permits under the Clean Air Act Tailoring Rule. EPA does not need to take further action for PSD permits to be legally required at gassy mines that might emit above the Tailoring Rule threshold.

Second, underground coal mines are currently being built and planned with emissions large enough to trigger PSD requirements. As noted in our October comments attached hereto, Walter Energy is developing a new mine in the gassy Blue Creek seam in Alabama.[3] An application to build Red Cliff Mine on Bureau of Land Management (BLM) land in Colorado has already drawn significant attention because of its expected methane emissions profile.[4] This list is not comprehensive but does indicate that new gassy mines are being developed. Both of these mines are expected to be gassy enough to require PSD permits. The Walter Blue Creek mine is similar to three existing mines that each liberate well over the 100,000 tonnes of CO_2-equivalent per year (tCO_2e/year) threshold over which a greenhouse gas PSD permit is required: in 2006, Blue Creek No. 7, No. 4, and No. 5 liberated 4.0, 3.0, and 1.2 million tonnes of CO_2-

[1] EPA RACT/BACT/LAER Clearinghouse. http://cfpub.epa.gov/RBLC/ (accessed 14 February 2014)
[2] *See*, RACT/BACT/LAER Clearinghouse, *at* http://cfpub.epa.gov/RBLC/ (accessed 14 February 2014)
[3] Walter Energy. Jim Walter Resources. http://walterenergy.com/operationscenter/jwr.html (accessed 11 February 2014).
[4] Earthjustice. "Pollution Giant: New Colorado Coal Mine." http://earthjustice.org/features/pollution-giant-new-colorado-coal-mine (accessed 11 February 2014).

equivalent per year ($MTCO_2e$/year), respectively.[5] If built, Red Cliff Mine in Colorado is expected to liberate 3.1 $MTCO_2e$/year.[6]

Third, we focus these comments on providing further evidence that methane destruction should be considered BACT at essentially all gassy mines expected to trigger PSD permitting requirements. This means that excluding these mines or mine expansions from participation in the Protocol avoids a potentially harmful perverse incentive that could weaken implementation of the Clean Air Act without restricting mines from participating in the Protocol that should not otherwise be required to capture drainage methane.

BACT determination

According to the Clean Air Act, Best Available Control Technology (BACT) is an emission limitation "based on the maximum degree of reduction of each pollutant subject to regulation . . . emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility. . ."[7]

When determining BACT, regulatory agencies place the responsibility for presenting and defending the technology selection on the applicant.[8] The BACT permit applicant typically undertakes the following five steps: "(1) identify available pollution control options; (2) eliminate the technically infeasible options; (3) rank the remaining control technologies by control effectiveness [at eliminating the pollutant in question]; (4) evaluate the most effective controls (considering energy, environmental, and economic impacts) and document the results; and (5) discuss the appropriate BACT selection with the permitting authority."[9] The EPA considers this five-step process very important to ensure proper compliance[10]

If the applicant believes that the top pollution control option is inappropriate as BACT, the rationale for this finding must be fully documented for the public record.[11] Furthermore, the applicant should not argue that a control option is inappropriate for economic reasons unless the average cost-effectiveness of a BACT control option (calculated by dividing the annualized cost of its implementation by the pounds of pollutant reduced) is unduly burdensome compared to the

5 EPA. 2009. Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006. EPA 430-K-04-003.

6 Bureau of Land Management. Red Cliff Mine Environmental Impact Statement Table 4-6. http://www.blm.gov/co/st/en/BLM_Programs/land_use_planning/rmp/red_cliff_mine.html (accessed 11 February 2014).

7 42 U.S. Code § 7479

8 Memo to Regional Administrators, I-X: Guidance for Determining BACT Under PSD at p4, http://www.epa.gov/region07/air/nsr/nsrmemos/bactupsd.pdf (accessed 11 February 2014).

9 New Source Review 90-Day Review Background Paper at p6, http://www.epa.gov/nsr/documents/nsr-review.pdf (accessed 11 February 2014).

10 See many of the EPA comment letters on GHG permitting actions, e.g. Comments on Intent-to-Approve for Pacificorp Lake Side Power Plant, Block #2, http://www.epa.gov/nsr/ghgdocs/20110304pacificorplakeside.pdf (accessed 11 February 2014).

11 Draft New Source Review Workshop Manual at B29, http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf (accessed 11 February 2014).

cost effectiveness of similar projects for other sources in the national BACT clearinghouse.[12] Both EPA guidance documents and the Clean Air Act definition of BACT demonstrate an expectation that the selected BACT should be the most effective abatement technology that is both technically feasible and not unduly burdensome to the facility owner.

Mine methane capture at drainage wells should be considered BACT

EPA assessment[13] indicates that capture of drainage methane is available, technically feasible, environmentally effective, and cost effective, so it is reasonable to expect that it will be ruled BACT given the five step process outlined above.[14]

In late 2013, EPA published analysis of domestic, additional greenhouse gas abatement potential as part of a broader effort to characterize global abatement opportunities for non-CO_2 GHG emissions.[15] Among other purposes, the analysis directly informs the United States' 2014 Climate Action Report to the United Nations Framework Convention on Climate Change,[16] indicating that the data constitute EPA's present understanding of abatement potential. Coal mine methane control opportunities are identified in three categories: capture drainage methane for use; flare drainage methane; and destroy ventilation methane. In 2006, 12 out of 24 mines with drainage wells captured 80% to 100% of their drainage methane in order to sell that methane into a pipeline.[17] EPA's 2013 analysis of additional mitigation opportunities in coal mine methane control indicates such financial benefits are typical even for sites that are not currently capturing (since the analysis focuses on additional mitigation potential), with an average breakeven price for on site methane capture below $0/t$CO_2$e (these projects are income generating: average costs range from an average of -$5/t$CO_2$e to -$1/tCO_2e, depending on the particular form of use).[18]

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12 "The presumption is that sources within the same category are similar in nature, and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same source category . . . Thus, where a control technology has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if *any*, between the application of the control technology on those other sources and the particular source under review" (emphasis in the original) http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf at B29, B31

13 Environmental Protection Agency. Global Mitigation of Non-CO2 Greenhouse Gases. December 2013. http://www.epa.gov/climatechange/EPAactivities/economics/nonco2mitigation.html (accessed 11 February 2014).

14 In a prototypical BACT example provided as Appendix G to (6), capture and destruction are demonstrated to be reasonable BACT options for a landfill, which shares many characteristics with gassy underground mines.

15 Environmental Protection Agency. Global Mitigation of Non-CO2 Greenhouse Gases. Table 1-5. December 2013. http://www.epa.gov/climatechange/EPAactivities/economics/nonco2mitigation.html (accessed 11 February 2014).

16 2014 CAR: United States Climate Action Plan. January 2014. http://www.state.gov/documents/organization/219038.pdf (accessed 13 February 2014).

17 Environmental Protection Agency. 2009. Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006. EPA 430-K-04-003.

18 Environmental Protection Agency. Global Mitigation of Non-CO2 Greenhouse Gases. Table 1-5. December 2013. http://www.epa.gov/climatechange/EPAactivities/economics/nonco2mitigation.html (accessed 11 February 2014).

In those cases where capture for use might not be cost effective for the mine owner, which we anticipate are unusual cases for mines that trigger PSD, EPA publications show that flaring is a cost effective abatement technology. The breakeven price for flaring at active underground coal mines is, on average, a little over $6/tCO_2e$,[19] and flaring can be implemented at any mine with a drainage system, not just those near pipeline infrastructure or with on-site or nearby natural gas demand. In addition, EPA's marginal abatement analysis shows that about 75% of the total 2010 abatement potential – which comprises the maximum amount of abatement of mine methane at a facility level, including ventilation methane – is available at a breakeven carbon price of less than $10/tCO_2e$. (The proportion is roughly the same for 2020 and 2030 marginal abatement opportunity.)[20] Thus, since both methane capture and destruction are technically feasible (the second BACT process criterion), effective at destroying methane (the third BACT process criterion), and not unduly burdensome compared to the cost effectiveness of similar projects for other sources (the fourth criterion), they can be assumed to be BACT. For example, see Table 1-7 in (15) to see that mitigation for landfill methane in covered landfills, which are similar to coal mines in many ways, is expected to cost between -$2/tCO_2e$ and $10/tCO_2e$ on average, with flares costing $5-6/tCO_2e$ (vs $6.3/tCO_2e$ for a mine). Notably, most capture-for-use applications for landfills are expected to have positive costs rather than generate revenues as they do for most coal mine applications. Methane flaring has been included as BACT in at least one PSD permit from the EPA RACT/BACT/LAER Clearinghouse.[21] The 2008 PSD permit for the expansion of the Rumke Sanitary Landfill in Ohio lists flaring as BACT.[22]

We note that an assumption that states with gassy coal mines will systematically rule extremely weakly on BACT for mine methane is not a valid reason to dismiss the concerns we raise in this section. First, controls are very often cost effective even without regulation. We also call attention to actions like Colorado's 2013-2014 Oil and Gas Rulemaking Effort, under which Colorado is considering adopting EPA's full oil and gas New Source Performance Standards (NSPS) recommendations in addition to more stringent control measures for oil and gas.[23] Colorado is one of the states where new gassy underground mines are being planned. The state's ruling on oil and gas regulation demonstrates that Colorado cannot be dismissed as a lax BACT permitting authority.

We have shown here that drainage methane capture meets EPA BACT determination guidance for essentially all mines that might require PSD permits. We have also discussed briefly above and in more detail in earlier comments that there is a tangible and real risk that, as currently drafted, the Protocol could incentivize state agencies to accept weaker BACT determinations than they otherwise would have. We therefore recommend that the Board choose

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[19] Id.

[20] Environmental Protection Agency. Global Mitigation of Non-CO2 Greenhouse Gases. Data Annex: col_mac_output_epa.xlsx. December 2013. http://www.epa.gov/climatechange/EPAactivities/economics/nonco2mitigation.html (accessed 11 February 2014).

[21] EPA RACT/BACT/LAER Clearinghouse. http://cfpub.epa.gov/RBLC/ (accessed 14 February 2014)

[22] See RBLC ID #OH-0330

[23] Colorado Department of Public Health and Environment, Air Pollution Control Division. 2013-14 Oil and Gas Rulemaking Effort http://www.colorado.gov/cs/Satellite/CDPHE-AP/CBON/1251635574914 (accessed 11 February 2014).

to exclude from crediting any drainage methane at a new mine or major mine modification that would require a PSD permit. Restricting this eligibility eliminates the incentive for state permitting authorities to weaken GHG PSD permit requirements, and would avoid any conflict with EPA's regulation of greenhouse gases. Importantly, it would accomplish this without any disadvantage, since the only mines that would be prevented from participating in the Protocol due to this change would be mines that should be required to capture methane under the PSD permitting process. We believe that there is a very strong case for eliminating eligibility for mines requiring PSD permits for crediting under the Protocol.

2. **In order to avoid increasing mine profits by amounts large enough to extend the lives of some mines, the Board should consider eliminating eligibility of drainage methane flaring at active mines or placing a fee on credits generated by this project type.**

There is substantial evidence that flaring projects from drainage wells at active underground mines can increase mining profits enough to affect mining operation. A simple assessment of eight of the ten US coal mines with drainage wells that do not already capture most of their drainage methane shows the potential for offset revenues to increase mining profits by 2% to 59% at $10 per offset credit (see Table 1 in our comments to the Board from 23 October 2013 attached hereto). These large profits are due to the large quantities of methane currently vented from these wells and the low cost of implementing and operating flaring systems. While increases in mining profits will be even larger if offset prices rise, profits at $10 per offset credit are already large enough to extend the life of a struggling gassy mine. Excluding flaring or creating a differential offset price for flaring projects with a fee can avoid large windfall profits to the gassiest mines.

In addition, this recommendation (in either of its variations) also creates greater incentive for mines to capture drainage methane for productive use rather than for flaring. The Board should design the Protocol to create incentives for the capture and use of drainage methane when such projects are cost effective with offset credit sales. Under the current draft Protocol, it is likely that mines that do not already capture methane for use will find flaring more cost effective than pipeline sales because flaring projects are less expensive to implement. Since mine methane is a valuable natural resource with added benefit to the climate if it is used, the Board should avoid incenting flaring when use is reasonably possible with the help of the Protocol.

Lastly, we suggest that the Board commit to monitoring the offset profits earned from drainage methane and ventilation air methane (VAM) capture projects as offset prices change and as experience is gained with these technologies. We suggest that the Board include provisions for a response if, in fact, profits become large enough to extend mine operation.

Our economic analyses continue to show the potential for windfall profits to coal mining operations from the incentives created by the Protocol. We look forward to reviewing the Board staff's analysis of the potential for these profits.

3. **Furthermore, incentives for mines to flare methane that would otherwise have been injected into a pipeline is a second reason to specifically eliminate eligibility of drainage methane flaring at new underground mines.**

At recent natural gas and carbon allowance prices, a mine operator would receive greater income from offsets for flaring methane from drainage wells than from selling that methane into a natural gas pipeline. This is true even when the greater costs of implementing a pipeline injection system compared with a flaring system are ignored. The Board has largely avoided incentivizing mines that already pipeline inject to switch to flaring by making drainage methane ineligible for crediting if a well has captured methane for pipeline injection within the previous year. But the incentive to flare instead of pipeline inject is not avoided for new mines. Operators of new underground gassy mines that may have otherwise chosen to sell their methane into a pipeline in the absence of the Protocol can choose to flare this methane to earn carbon credits. This would not only result in substantial non-additional crediting (methane destruction would be credited that would have happened through pipeline injection without the offset protocol); it would also have the added impact of flaring methane that would otherwise have been put to productive use. While we recognize that new mine wells are not expected to be a major source of projects under the Protocol, given current market conditions, this specific exclusion would avoid non-additional crediting and the broader effects of causing methane to be flared that otherwise would have been used productively. We emphasize that the Protocol should be robust to changes in global fossil fuel markets as they have a long history of volatility. (See Figure 1 from our comments from 1 July 2013 for a more detailed discussion of this concern.)

4. **The Board should clarify in its additionality assessment of mine methane capture at abandoned mines (section 3.4.2(b)(4)) that methane capture by pipeline injection systems installed when mines were active is either common practice or is excluded from the evaluation in this section.**

We recommend that the language in section 3.4.2(b)(4) be clarified in the following way so that it more clearly reflects the additionality of methane capture at abandoned mines.

3.4.2(b)
(4) Abandoned Mine Methane Recovery Activities
(A) Destruction of extracted mine methane via any end-use management option other than injection into a natural gas pipeline for off-site consumption with a pipeline injection system installed when the mine was active automatically meets the performance standard evaluation because it is not common practice nor considered business-as-usual, and is therefore eligible for crediting under this protocol.
(B) Pipeline injection of mine methane at abandoned mines that injected drainage methane into a natural gas pipeline for off-site consumption when the mine was active is common practice and considered business-as-usual, and therefore ineligible for crediting under this protocol.

This change reflects that it is common practice for pipeline injection at active mines to continue after mine closure. This clarification does not affect project eligibility under the

Protocol. Section 2.4(b) already states that pipeline injection systems installed by active underground mines cannot be considered eligible offset projects after mines have been abandoned. Still, we recommend that section 3.4.2(b)(4) be amended to reflect that the capture of abandoned mine methane by pipeline injection systems installed when mines were active is common practice. Alternatively, ARB could make the same correction by stating explicitly in that section that this methane capture is excluded from the evaluation of abandoned mine methane.

The arguments we make below (1) support the need for this clarification, (2) support the exclusion of pipeline injection at abandoned mines by mines that captured methane for pipeline injection when they were active as per section 2.4(b), (3) provide supporting evidence for the additionality of the abandoned mine portion of the Protocol with this exclusion, and (4) demonstrate the steps we recommend the Board use to conduct a full additionality assessment of any project type being considered for offset crediting under a new or revised protocol.

<u>A simple common practice assessment</u>

The Board's common practice assessment of MMC at active underground mines found that a subset of possible MMC projects – projects injecting methane into a pipeline – is common practice. These projects were excluded from the draft protocol. Similarly, for abandoned mines, it is very common practice for mines that captured drainage methane for pipeline injection when active to continue pipeline injection once abandoned. *Every* mine that pipeline injected when it was active that was closed since 1996 continued to pipeline inject when it was abandoned.[24]

This assessment holds, even though three of these mines participated in a voluntary offset program making their additionality uncertain.[25] The majority of these mines – five out of eight – did not participate in a voluntary offset program and so are clearly business-as-usual (did not require offsets to be built). Further, all eight abandoned mines have characteristics that point to the cost effectiveness of methane capture without the need for offset credits, including the three that participated in the voluntary offset market. They each have large releases of methane, and already had pipeline injection infrastructure in place when the mine was abandoned.

A simple common practice assessment as described herein, similar to that used by the Board to assess the additionality of active underground mines, should lead to the conclusion that

[24] We listed all active underground mines that captured methane in 1996 and 2006 from two reports: Environmental Protection Agency. 1997. *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Draft Profiles of Selected Gassy Underground Coal Mines*, and Environmental Protection Agency. 2009. *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006.* EPA 430-K-04-003. We examined whether each of these mines is currently active or closed using three methods: (1) the listing of abandoned mines capturing methane in a personal letter from Ronald C. Collings, V. P., Ruby Canyon Engineering, Inc. RE: California Air Resources Board: Proposed Compliance Offset Protocol Mine Methane Capture Projects, dated August 19, 2013. to Jessica Bede, California Air Resources Board. Dated October 22, 2013, (2) Mines dataset from the Mine Safety and Health Administration (MSHA) listing all mines in the country by type and status, and (3) internet searches for articles on each of the mines.

[25] Aberdeen mine is listed under the Verified Carbon Standard, and Blue Creek No 3 and No 5 mines are listed under the Chicago Climate Exchange.

this one subset of abandoned mine methane capture is common practice. This should be clarified in section 3.4.2(b)(4).

A full additionality assessment

The importance of excluding pipeline injection systems installed when mines were active from crediting under the Protocol becomes clearer and even more compelling with a focus on credits rather than on projects. Generally, we recommend that the Board conduct the following additionality test on any project type being considered for offset crediting. Using this test, any project type would be considered to meet AB 32's additionality requirement if, focusing just on that project type:

1. the expected effects of the Protocol on new project development substantially exceeds the crediting of activities that would have be built on their own, and
2. conservative methods of estimating emissions reductions is estimated to under-credit emissions reductions by at least the amount of over-crediting expected to result from non-additional projects participating in the Protocol.

Since such an assessment is based on uncertain predictions of the future, we do not recommend a single cut-off value as a passing mark for this test. Instead, this is a reasonableness test. The purpose is to assess if it is reasonable to claim that the inclusion of a certain project type under a Protocol is not likely to credit more reductions than actually enabled, by quantitative assessment of a conservative business-as-usual scenario. We apply this test to abandoned mine methane capture.

Over the last ten years, three gassy underground mines that captured methane from drainage wells were abandoned. These abandoned mines currently capture methane approximating 2.2 million tonnes of CO_2-equivalent per year ($MTCO_2e/y$).[26] A similar magnitude of emissions were released by mines abandoned in the previous decade. From 1994 to 2003, five mines were abandoned that continued pipeline injection with systems installed when the mines were active. While we do not have emissions data from these mines, they are in similar coal seams to the mines abandoned in the last ten years, and so can be expected to have captured similar amounts of methane in the first ten years after abandonment. Therefore, this magnitude of business-as-usual methane capture seems like an amount of methane that could reasonably be captured without the help of offset credits from mines with drainage systems that will be abandoned over the next ten years. Based on data from the past two decades, we estimate that over the next ten years around 2.2 $MTCO_2e/y$ of non-additional credits could reasonably be generated by the Protocol if mines that captured methane for pipeline injection when they were active are allowed to generate credits from those systems once the mines are abandoned.

Ruby Canyon Engineering estimates that the total potential methane capture from mines have already been abandoned but are not already capturing methane is approximately 2.3 $MTCO_2e/y$.[27] This means that in the best case, if *all* abandoned mines with the potential to

[26] personal letter from Ronald C. Collings, V. P., Ruby Canyon Engineering, Inc. RE: California Air Resources Board: Proposed Compliance Offset Protocol Mine Methane Capture Projects, dated August 19, 2013. to Jessica Bede, California Air Resources Board. Dated October 22, 2013

[27] Ruby Canton Engineering, Inc. 2013. Abandoned Coal Mine Methane Offsets Protocol: Background Information on Performance Standard and Additionality

capture methane with the help of California's offsets program were to install methane capture devices over the next ten years, around half of all methane captured from new projects would still be non-additional.

It can reasonably be expected that only some fraction of the maximum potential methane capture from existing abandoned mines will be built. It can therefore be expected that without the exclusion in 2.4(b), the quantity of non-additional credits from pipeline injection systems installed by active mines would overwhelm methane captured by truly additional development at abandoned mines. This discussion strongly supports the exclusion of continued pipeline injection after mine closure from crediting under the Protocol as specified in section 2.4(b).

With the exclusion in section 2.4(b), the additionality of the abandoned mine section of the Protocol is reasonably solid. We now examine the common practice of new methane capture systems at abandoned mines (i.e. those that continue to be eligible under the current draft of the Protocol). Over the last ten years, seven new methane capture systems were built at fifteen abandoned mines.[28] These projects captured a total of 0.15 $MTCO_2e/y$ of methane. Of this, 0.03 to 0.15 $MTCO_2e/y$ would have been built without the help of an offset program. 0.03 $MTCO_2e/y$ was captured without voluntary offset credits. It is unclear how much of the methane captured under a voluntary offset program is truly additional (would not have been built without the offset program). The two voluntary offsets programs with MMC projects at abandoned mines – Verified Carbon Standard (VCS) and the Chicago Climate Exchange (CCX) – use a project-by-project approach to additionality testing, which has been proven to be inaccurate at testing additionality.[29] The additionality of one of the projects listed under a voluntary offset program is questionable.[30] Over the last ten years, 0.03 to 0.15 $MTCO_2e/y$ of methane was captured by new systems installed at abandoned mines that were possibly viable on their own without carbon credits. We are unaware of reasons why new methane capture installations at existing abandoned mines would increase substantially over the next decade. Continued rates of non-additional methane capture at abandoned mines - 0.03 to 0.15 $MTCO_2e/y$ – is relatively small compared to the 2.3 $MTCO_2e/y$ potential for methane capture with the help off offsets revenues estimated by Ruby Canyon Engineering.

The magnitude of this non-additional crediting (0.03 to 0.15 $MTCO_2e/y$) could easily be compensated for by the amount that the Protocol underestimates reductions from truly additional projects expected to be developed using the Protocol. The abandoned mine portion of the Protocol applies a 20% uncertainty deduction for baseline emissions. That is, actual crediting is 20% lower than best estimates of these reductions. If the Protocol were to effectively enable 0.75 $MTCO_2e/y$ of additional methane capture over the next ten years (around one third of the total potential), the underestimation of reductions from these projects due to the 20% discount factor

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[28] personal letter from Ronald C. Collings, V. P., Ruby Canyon Engineering, Inc. RE: California Air Resources Board: Proposed Compliance Offset Protocol Mine Methane Capture Projects, dated August 19, 2013. to Jessica Bede, California Air Resources Board. Dated October 22, 2013

[29] Barbara Haya. 2009. *Measuring emissions against an alternative future: fundamental flaws in the Kyoto Protocol's Clean Development Mechanism.* Energy and Resources Group Working Paper, University of California, Berkeley

[30] See description of Grayson Hill Farms abandoned mine methane capture project in Baker, T. & R. E. Nelson (2005) Creating Something from Nothing: Resource Construction through Entrepreneurial Bricolage. *Administrative Science Quarterly,* 50.

would compensate for 0.15 $MTCO_2e/y$ of non-additional crediting. This is assuming that similar quantities of non-additional methane capture occur in the next ten years as the last ten years. Given that some of this methane will be captured for use, displacing other emissions, the under-estimation of emissions reductions from truly additional projects will be even greater.

Over time, the Board should monitor the MMC offset projects at abandoned mines. If there is no clear indication of increased abandoned mine methane capture due to the Protocol, in terms of scale or characteristics of the projects, with reductions sufficient to compensate for the risk of non-additional crediting estimated here, the Board should consider amending the Protocol to further restrict potentially non-additional projects from crediting.

(5) We recommend the following clarification: The Protocol's definition of "non-qualifying destruction device" as "a destruction device that is. . . operational at the mine prior to offset project commencement. . ." is meaningless because "offset project commencement is *defined* as the date at which the offset project's mine methane capture and destruction equipment becomes operational." (Section 3.6). In resolving this language, the Board should make sure the following provisions are preserved:

1. Devices that were installed prior to the date of project listing, or more than one year prior to project listing, should be considered ineligible for crediting, and
2. Any active underground mine that injected drainage methane into a pipeline should not be able to do so as an offset project after abandonment.

We believe that the following changes to the Protocol language retain the Board's intended meaning which we understand as including the two bulleted points just above.

We first note that the definition of Offset Project Commencement in the Protocol matches the definition of Offset Project Commencement of in the cap-and-trade regulation. We believe that this definition should not be changed in the process of resolving the contradictory language in the Protocol:

> Section of the Protocol: § 3.6. Offset Project Commencement.
> (a) For this protocol, offset project commencement is defined as the date at which the offset project's mine methane capture and destruction equipment becomes operational. Equipment is considered ~~*operational*~~ operational on the date at which the system begins capturing and destroying methane gas upon completion of an initial start-up period.

Another reason not to change definition of "offset project commencement" in the Protocol is to preserve the meaning of section 95975 of the cap-and-trade regulation for this Protocol This section of the regulation mandates that an offset project must be listed within one year of "offset project commencement," where "offset project commencement" is defined in the regulation as the beginning of construction work or of installation of equipment or materials.

We suggest that the definition of "non-qualifying device" from the Protocol be changed in the following manner (our suggested changes are double underlined and double cross out):

> DEFINITIONS:
> (33) "Non-Qualifying Destruction Device" or "Non-Qualifying Device" means a destruction device that is either operational at the mine prior to offset project ~~commencement~~ listing or used to combust mine methane via an ineligible end-use management option per section 3.4. A destruction device that is operational at the mine prior to offset project ~~commencement~~ listing is considered a non-qualifying destruction device even if retrofitted thereafter. Methane destroyed by a non-qualifying device must be monitored for quantification of both the baseline and project scenarios.

It is important that devices that were installed prior to the date of project listing (this seems to be what is meant by Protocol's definition of non-qualifying device), or more than one year prior to project listing (specified in new changes to section § 95975(h) in the cap-and-trade regulation), remain ineligible in order to prevent the participation of non-additional projects in the Protocol. If a project is additional, project developers should be motivated to comply with Protocol requirements in a timely manner. A project developer that realizes the restriction months or years after the project is operational most likely did not need the offsets income to implement their project.

We suggest the same change (replacing the word "commencement" with "listing") in the following sections: Definition of "qualifying device", 2.1(b), 2.2(b), 2.3(b), 2.4(b)

We note, that in resolving this language, it is also important not to change the meaning of section 2.4(b) of the Protocol which specifies that an active mine that pipeline injects cannot then generate offset credits from that same capture system once the mine is abandoned. We provide a detailed defense of this restriction in Section #4 above.

We greatly appreciate and thank the Board for the opportunity to share our comments on this informal draft of the MMC Compliance Offset Protocol.

Most sincerely,

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Attachment: Stanford Law School comment letter to the Board dated 23 Oct 2013

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23 October 2013

California Air Resources Board
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Comments on the California Air Resources Board's Draft Mine Methane Capture (MMC) Compliance Offset Protocol Released September 4, 2013

Thank you for the opportunity to comment on the draft Mine Methane Capture Compliance Offset Protocol (the "Protocol") being considered for adoption by the California Air Resources Board (the "Board") under its cap-and-trade program. Over the course of our participation in the Technical Working Group tasked with informing the development of the Protocol, we provided input on several ways the Protocol may result in the substantial over-crediting of greenhouse gas emissions reductions. We provided specific recommendations on steps the Board could take to further examine and to remedy each of these issues. We described our concerns in written comments submitted on July 1 and August 22, 2013 to the Board (attached hereto as appendixes) and have raised these concerns within the context of the Technical Working Group meetings and with Board staff outside of those meetings. While we have learned a great deal from these exchanges of information, as of yet, neither the responses published in the Staff Report accompanying the September 4th release of the draft Protocol, nor the draft Protocol itself, have sufficiently addressed these issues. Considering that the MMC Protocol is the first protocol that the Board is developing itself, that it has the potential to generate a large quantity of credits, and that other offsets programs to date have received wide-spread criticism for non-additional crediting, it is especially important that the Board make clear that it has performed analysis and taken measures to ensure that the credits generated by this Protocol will be real and additional.

We believe that the current Protocol, in the absence of additional analysis or mitigatory measures, risks significant over-crediting of emissions reductions, and failure to meet the statutory requirements of AB 32. We recognize that, in all offsets protocols, some amount of non-additional or non-real crediting is likely and is anticipated and that no protocol will be perfect. Our concern is that without further and detailed analysis and precautionary measures to address specific outstanding issues, the current protocol risks generating enough credits that are not based on real emissions reductions that it could substantially undermine the credibility, integrity, and ultimately, the efficacy of the entire Offsets Program. We present each of these concerns in the comments below with specific suggestions on how the Board may proceed with addressing each one. None of these suggestions would be difficult to implement.

Finally, given recent assessments of the California market for allowances which suggest that allowance prices are expected to remain close to floor levels almost through 2020, there seems to be no reason for the Board to rush forward with the adoption of a Protocol before it has performed the analysis and modifications needed to be confident that the Protocol meets the requirements of AB 32. Since the Board is in a position to create an offsets program that serves as a model for other programs, doing the proper analysis and taking conservative precautionary decisions about project eligibility not only has implications for the environmental integrity of California's cap-and-trade program, but has the potential to influence cap-and-trade programs in other jurisdictions well beyond California through precedent and example.

What Still Needs to Be Done Prior to Protocol Adoption

1. Additionality of abandoned mines: Approximately one third of all methane liberated from abandoned mines in the United States is currently captured and destroyed. MMC projects at abandoned mines continue to be implemented. Non-additional projects would generate a large portion of offsets credits from abandoned mines, unless (1) the Protocol were to effectively incentivize many more truly additional projects than participating non-additional projects, and (2) conservative methods of estimating emissions reductions from participating projects result in an under-crediting of reductions at least as large as the non-additional crediting.

RECOMMENDATION: Eligibility criteria should be established for abandoned mines so that the total credits generated by abandoned mines is expected to be additional based on conservative business-as-usual scenario analysis. In particular, the Board should consider excluding abandoned mines that captured methane for use when active (not including flaring) on the basis that methane capture at such mines is common practice.

2. Conflicting incentives: Incentives created by the Protocol may weaken implementation of greenhouse gas regulations under the federal Clean Air Act. Incentives may also cause mine owners to flare methane that would have been injected into a pipeline in the absence of the Protocol. Both of these incentives only apply to new underground mines and underground mines that have undergone major modification.

RECOMMENDATION: The Protocol should either include refined eligibility criteria for projects at new underground mines and at underground mines that have undergone major modification to avoid these "perverse incentives," or new and majorly modified active underground mines should be excluded outright.

3. Improving coal mine profits: The Protocol has the potential to substantially improve coal mining profits for some participating coal mines, improving their financial standing at the present time when coal is competing neck-to-neck with natural gas and many coal mines are shutting down.

RECOMMENDATION: The Board should only adopt the Protocol if conservative analysis shows that the increase in mining profits from offsets revenues will not result in an increase in production or use of coal, or that any increase will be small and is accounted for by the Protocol.

1. **<u>Additionality of abandoned mines</u>: Eligibility criteria should be established for abandoned mines so that the total credits generated by abandoned mines is expected to be additional based on conservative business-as-usual scenario analysis. In particular, the Board should consider excluding abandoned mines that captured methane for use when active (not including flaring) on the basis that methane capture at such mines is common practice.**

At present, around one third of all methane liberated from abandoned mines in the United States is captured and destroyed. This methane is captured and destroyed by projects at 38 abandoned coal mines.31 This means that if all new mine methane capture at abandoned mines were eligible for crediting, as currently written in the draft MMC protocol, it is possible that a large proportion of the credits generated by abandoned mines under the Protocol will be from non-additional projects. This is especially possible due to large disparities in methane released from different abandoned mines and because mines that release the most methane are also most likely to capture methane without the offset protocol. Measures must be taken to avoid the generation of credits from non-additional projects, or even a single large non-additional project, that would make up a sizable portion of total credits generated by the protocol.

> <u>ARB staff response to this issue</u>: Board staff has determined that methane capture at abandoned underground mines is not "common practice," and therefore is additional. This is based on an analysis of the number of abandoned mines where methane capture occurs now (38) out of the pool of gassy mines that have been abandoned in the country since 1972 (>400).

We do not believe that this analysis sufficiently shows that large-scale over-crediting is unlikely to result from the abandoned mine portion of the Protocol. In particular, we are concerned that, under the Protocol as currently written, the number of offsets credits generated from large business-as-usual MMC projects at abandoned mines could overwhelm the number of credits generated by truly additional projects. We believe that changes need to be made to the eligibility criteria for abandoned mines to avoid crediting mines most likely to capture methane on their own after abandonment, and suggest procedures for assessing whether the abandoned mine portion of the Protocol is expected to avoid over-crediting after such exclusion. We describe the terms of this analysis below.

1. <u>Additionality assessments should be based on the quantity of methane being captured, in addition to the number of mines capturing that methane.</u>

The impact of the offsets program on the effectiveness and integrity of the Board's cap-and-trade program is a matter of the quantity of offsets credits produced and the quality of those offsets in terms of the real additional reductions they represent. The atmosphere only "cares"

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31 Ruby Canyon Engineering, Inc. (2013). *Abandoned Coal Mine Methane Offset Protocol: Background Information on Performance Standard and Additionality*. http://www.arb.ca.gov/cc/capandtrade/protocols/mmc/rceammbackground.pdf (accessed 21 Aug 2013).

about total emissions, and total real reductions, not if those reductions come from one mine or many.

An extreme example might be useful in explaining this point. Let's say that the MMC protocol credits reductions from 100 abandoned mines. Let's also say that one of these abandoned mines vents 10,000 units of methane, and the other 99 mines vent 1 unit of methane each. The outcomes of this protocol on the Board's cap-and-trade program rest almost exclusively on what happens with the one high-emitting mine. If the high-emitting mine would have implemented an MMC capture project on its own without the protocol (the project is non-additional), then the resulting false crediting would overwhelm any emissions benefit from the 99 other MMC projects. This example should demonstrate that when sizes of projects vary, it is important to look at the effect of a protocol on emissions, not just on numbers of projects. Methane emissions from underground and abandoned mines vary by several orders of magnitude.

2. <u>Current practice should be evaluated for subsets of mines expected to participate in the Protocol.</u>

In the Staff Report, the Board Staff indicated that a performance standard analysis of additionality was undertaken for a subset of active underground mines (i.e., those with drainage systems). For abandoned mines, it appears that no analysis was done of similar subsets of abandoned mines (i.e. abandoned underground mines with drainage systems, or mines that had MMC projects while active). In addition to the entire population of potential projects, a robust additionality assessment under a conservative business-as-usual scenario must also examine subcategories of potential projects that are easily distinguishable in a way that is relevant to the question of additionality. We believe that this approach should be used for performance standard analyses for all future Protocols.

<u>The Board should consider excluding mine methane capture projects installed at abandoned mines that captured methane for use (not including flaring) when active without offsets because these projects are common practice.</u> We make this recommendation on the basis that it is common for mines which captured methane while active to also capture methane upon abandonment.32 If a mine captured methane while active under the Board's offsets program the mine should be allowed to complete its 10-year crediting period if it closes during that period.

Certainly one potential downside to this exclusion is that allowing all mines to generate offsets when abandoned would create an additional financial incentive for mines to close. However, we understand that the Board should be primarily concerned with ensuring that the Protocol meets the requirements laid out by AB 32 that credits must be real and additional. The Board should only consider risking the generation of non-additional credits if the potential for the Protocol to incent mine closures is so large that the emissions savings from the effects of the protocol from mine closers clearly outweighs the expected non-additional crediting that would result from including these mines.

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32 Communication with industry expert.

3. The majority of credits that would be generated by abandoned mines under the current draft protocol is likely to be from non-additional projects. Steps need to be taken to avoid non-additional crediting.

We understand that since 2000, mine methane capture projects have been installed at five abandoned mines which were not registered under a voluntary offsets program.33 We also understand that the MMC protocol, at current offsets prices, is expected to enable on the order of five to ten additional projects to be implemented.34 While a past rate of business-as-usual project development is only an approximate predictor of near-term future development, and the estimate of five to ten new additional projects is one individual's informed estimate, these numbers provide one possible, and not unlikely, scenario for the outcomes of the Protocol on abandoned mines. This scenario points to a substantial portion of the abandoned mines participating in the Protocol being non-additional. If the business-as-usual projects were larger in size than the truly additional projects (likely because larger projects are more cost effective and more likely to move forward on their own), then the proportion of non-additional credits could be substantially greater than half of the credits generated.

Further, a total of seventeen MMC projects were implemented at abandoned mines since 2000 including projects which participated in a voluntary offsets protocol.35 It is well documented that the type of additionality assessment performed by these voluntary offsets programs has been ineffective at filtering out non-additional projects. To the extent that these projects would have been implemented without the offsets income (are non-additional), the total quantity of business-as-usual methane capture would be even greater. A detailed review of MMC projects at abandoned mines participating in voluntary offsets programs should lend some insight into the additionality of these projects.

4. We recommend the Board adopt the following method for assessing additionality.

We advise the Board to conduct the following analysis to assess the expected results of the Protocol on emissions. This analysis would be performed on the pool of abandoned mines that could implement MMC projects with the help of the Protocol, not including the mines that would be excluded through the analysis described above. We understand this approach to be practical and feasible, and the best way to assess the additionality of a protocol, given the limitation that we only have the past and the present to predict the future.

We believe an additionality assessment involves assessing:

33 Comment submitted to the Board by Ruby Canyon Engineering on the draft MMC protocol on October 22, 2013.

34 Estimate made by industry expert in informal conversation.

35 Comment submitted to the Board by Ruby Canyon Engineering on the draft MMC protocol on October 22, 2013.

1. The non-additional credits that are expected to be credited by the Protocol. This could involve assessing the credits that would have been generated by non-additional projects had the Protocol been adopted in the recent past (see discussion in point #3 just above).
2. The expected effect of the Protocol on new project implementation.
3. Any shifts in mine abandonment trends, MMC technologies and market factors that would suggest project implementation trends would differ from the past going forward.

The Protocol would be considered to meet the additionality requirements of AB 32 if:

4. the expected effects of the Protocol on new project development substantially exceeds the crediting of activities that would have be built on their own, and
5. conservative methods of estimating emissions reductions is estimated to under-credit emissions reductions by at least the amount of over-crediting expected to result from non-additional projects participating in the Protocol.

We believe that this is a common sense and practical approach to testing additionality, and that it is the best way for the Board to protect the environmental integrity of its offsets program.

6. <u>This additionality assessment should be supported by ex-post analyses of trends following the adoption of the Protocol.</u>

An ex-post analysis several years after Protocol adoption should confirm the expectations on which the Protocol was adopted, or rates of project implementation should be greater than predicted indicating even greater additional crediting. If a clear indication of the effects of the Protocol on project development is not apparent, further changes should be made to the Protocol so that the Board can avoid non-additional crediting.

7. <u>Conflicting incentives</u>: The Protocol should either include refined eligibility criteria for projects at new underground mines and at underground mines that have undergone major modification to avoid "perverse incentives," or new and majorly modified active underground mines should be excluded outright.

This modification is meant to avoid two potentially serious adverse effects of the current draft protocol that would increase emissions while also crediting non-additional (business-as-usual) reductions.

First, the Protocol may undermine effective implementation of greenhouse gas reductions under the federal Clean Air Act. Many new and major modifications to coal mines will need to receive Prevention of Significant Deterioration (PSD) permits for their emissions of greenhouse gas pollutants. No such permits have yet been written for coal mines; and the terms of those permits are determined by state-level agencies on a mine-by-mine basis. This permitting process requires each state granting a permit to determine the Best Available Control Technology (BACT) for reducing emissions from the source. Under the current Protocol, a tangible "perverse" incentive therefore exists for state agencies to determine that the technologies that capture methane that are used for offset credits under the Protocol are not BACT. Such determination would allow mines within their borders to receive offsets payments to capture methane instead of being required to capture that methane without compensation under state implementation of the Clean Air Act. This risk is particularly high at the present time since no state has yet made a first BACT determination for greenhouse gas emissions reductions from a coal mine. A weak BACT determination for mines planning to sell offsets could have wider effect if weakened BACT standards set a precedent for other mines in the state. It is important to emphasize that, despite the fact that states have not yet begun issuing PSD permits and making BACT determinations, such permit applications and determinations for new mines and major modifications to existing mines are anticipated under the Clean Air Act. No additional rule promulgation or new legislation is required for this implementation to take place.

Second, at current natural gas and carbon allowance prices, a mine operator would receive more revenue by selling offsets credits generated from flaring leaking methane than from selling that same methane into a natural gas pipeline (a project-type which is ineligible for offset credits because it is already considered common practice). This means that the Protocol would incent operators of new underground gassy mines or newly modified mines that would have otherwise chosen to inject their methane into a pipeline under business-as-usual to choose instead to flare the methane to earn offset credits. This would not only result in substantial non-additional crediting (methane destruction would be credited that would have happened through pipeline injection without the offsets protocol); it would also mean that methane is flared that would otherwise have been put to productive use.

Due to the relatively slow rate at which new underground mines are built and expanded, it is expected that the majority of credits potentially generated under the active underground mine portion of the Protocol will be from existing mines. By incenting the development of MMC projects at existing mines the Protocol helps generate experience with MMC technologies that will encourage MMC to be considered BACT. This positive influence of the Protocol on policy implementation is a form of positive leakage – emissions reductions supported by the Protocol but not credited under the Protocol. Because of the relatively small proportion of new and expanding mines expected to participate in the Protocol, excluding these mines should not substantially weaken this positive leakage effect.

However, it is also important to note that coal mines still are being built and expanded. For example, new mining at Alabama's Blue Creek seam, one of the country's most gassy coal seams, is being planned,36 and if built, would face both of the incentives described just above.

> ARB staff response to these concerns: These issues were not addressed in the *Staff Report* nor by the Protocol.

Both of the risks we raise are tangible, substantial, and largely avoidable. The potential for offsets to "perversely" incent state regulators to refrain from adopting climate-friendly policies have long been discussed and documented. Christiana Figueres, who serves as Executive

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36 http://walterenergy.com/operationscenter/jwr.html (accessed 17 October 2013)

Secretary of the UN Framework of Climate Change, documented several instances of countries refraining from enacting climate-friendly policy to enable facilities within the country to pass the legal additionality test of the Kyoto Protocol's offsets program and to generate offsets credits.37 At current natural gas and offsets prices, the offsets protocol creates a direct financial incentive for mine operators at new or expanded mines to flare methane instead of injecting their methane into a pipeline – a very real direct potential adverse effect of the protocol.

There is a simple, straight-forward solution to both of these risks. Both issues apply only to new underground mines and major modification to existing active underground mines. Both issues can be avoided by carefully defining project eligibility criteria to avoid crediting projects that could be considered BACT or mines where pipeline injection is feasible. Alternatively, these issues can be avoided by making drainage methane from new and majorly modified underground mines ineligible under the Protocol. Even if the Board decides to exclude these mines or mine expansions now, it can choose to include all or a subset of them in the future, after there is more clarity with regard to how BACT is determined for coal mines and if natural gas prices increase in a sustained manner.

In addition to the above, we recommend two other changes to the Protocol that would help avoid conflict with the Clean Air Act. First, we comment on this paragraph in the Protocol:

> Emission reductions achieved by an MMC project must also exceed those required by any law, regulation, or legally binding mandate at the time of offset project commencement. If no law, regulation, or legally binding mandate requiring the destruction of methane at the mine at which the project is located exists at the time of offset project commencement, all emission reductions resulting from the capture and destruction of mine methane are considered to not be legally required, and therefore eligible for crediting under this Protocol, subject to the performance standard evaluation above. (page 8).

We highlight the phrase "at the time of offsets project commencement." If mine methane capture were to become legally required in the middle of an offsets crediting period, such as through enactment of new Clean Air Act regulations, then any MMC project should cease to be allowed to generate offsets credits from the date when the MMC project is legally required to be implemented. Non-additional credits would be generated if a mine is allowed to generate offsets credits after MMC is legally required at the mine, even if that law was not in effect at the start of the MMC project.

Second, we understand that some new and expanded mines should have already requested greenhouse gas PSD permits but have failed to do so. California's cap-and-trade regulation requires all offsets project developers to attest that they are in "accordance with all applicable local, regional, and national environmental and health and safety laws that apply to

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37 Figueres, Christiana. 2006. Sectoral CDM: Opening the CDM to the Yet Unrealized Goal of Sustainable Development. International Journal of Sustainable Development Law & Policy. 2(1)

the offset project location."38 The Board should also require all MMC project operators to attest in writing specifically that the mine is in accordance with the greenhouse gas provisions of the Clean Air Act, and in particular, Prevention of Significant Deterioration (PSD) permitting requirements. This will help raise awareness among mine owners of PSD requirements, as well as help ensure that the Board does not run the risk of credit invalidation if a project is found to be out of compliance with this federal requirement after offsets credits have been generated.

(See Appendixes A & B from our comment letter dated July 1, 2013, attached hereto, for a more in depth discussion of these concerns and related recommendations.)

8. Improving coal mine profits: The Board should only adopt the Protocol if conservative analysis shows that the increase in mining profits from offsets revenues will not result in an increase in production or use of coal, or that any increase will be small and is accounted for by the Protocol.

In our July 1, 2013 comments to the Board on the Protocol (attached hereto) we showed that the Protocol has the potential to meaningfully increase the profits of some participating coal mines. We recommended that the Board perform a more detailed analysis examining the potential for increased profits to lead to an increase in the production and use of coal. We made this recommendation with the understanding that increasing coal mining profits must not be taken lightly. When offsets are allowed to be generated by high emitting industries, they in effect subsidize that industry. Subsidizing coal mining – the most carbon intensive of industries – is especially a concern at the present moment when, due to declines in natural gas prices, coal and natural gas are in close competition as fuels for electricity generation. Over the past few years natural gas has replaced some coal as base load in the United States, and small differences in fuel prices are affecting marginal dispatch of power plants. We recommended that the Board perform an analysis that examines the potential effects of the revenues generated by the Protocol on the production and use of coal.

ARB staff response to this concern: ARB staff assessed the potential financial impact of the Protocol on participating coal mines, estimating that offsets revenues would amount to less than one percent of mining revenues, and that offsets profits would amount to less than one percent of mining profits. They conclude that this small increase in revenues is inconsequential to the market. We understand that the Board's analysis is based on the assumption that a typical MMC project has a profit margin of around 15% (meaning that MMC project implementation costs equal around 85% of offsets revenues).

Our early analysis submitted to the Board in our letter dated July 1, 2013 showed that the effect of the MMC protocol on profits is potentially significant on some participating mines and pointing to the need for the Board to do its own analysis of this consequence of the Protocol.

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38 California Health and Safety Code section § 95975(c)(3)

We question the Board's assumption that the profit margin of MMC projects is only 15%. An analysis must not only assess the effects of the Protocol on an average mine, but also the effects on those mines most likely to participate in the Protocol and those most likely to be affected by the increased income. The Protocol will have a disproportionate impact on decisions at the gassiest mines and those mines that are on the verge of closing. To understand the impacts of the Protocol, the Board's analysis should assess those impacts on the range of mines it could influence.

We used the US Environmental Protection Agency's (EPA's) Coal Mine Methane Project Cash Flow Model to examine the costs of MMC projects for twenty sample projects.39 We build on our analysis from July 1 which estimated the potential effect of offsets, at $10 per tCO$_2$e, on ten gassy active underground mines that the EPA has identified as having drainage wells, but where mine operators were venting (i.e., not destroying) either all or nearly all mine methane emissions in 2006.40 We analyzed two methane capture projects at each mine: one which flared all of the drainage methane previously vented to the atmosphere, and a second which oxidized 50% of the ventilation air methane.

The EPA Cash Flow Model predicts that eight mines with drainage methane flows greater than one million cubic feet per day are viable candidates for flaring projects. These eight projects are predicted to have profit margins between 40% and 92%, with an average of 70%. The Cash Flow Model predicts that the mines with ventilation air methane (VAM) concentrations of 0.8% or greater are viable candidates for VAM oxidation projects. Predicted profit margins for these projects range from 40% to 53%, with an average of 46%. Each of these estimates used mine-specific methane flows and VAM concentrations as reported by the EPA,41 and mid-point values for each project cost parameter for which the Model displayed a range of possible inputs. The use of average values for all cost parameters means that some modeled MMC projects will have higher profit margins and others lower, depending on the actual cost of the particular project. We include a moderate assessment of annual monitoring and verification

TABLE 1: OFFSETS PROFITS AS % OF COAL MINING PROFITS

For hypothetical offsets projects
assuming a 9.4% coal mining profit margin without offsets

		at an offsets price of:		
Mine	**State**	**$10**	**$20**	**$50**
FLARING PROJECTS (using 100% of drainage methane)				
McElroy Mine	WV	4%	7%	18%
Bailey Mine	PA	6%	12%	31%
San Juan South	NM	10%	20%	50%
West Elk Mine	CO	59%	118%	296%
Robinson Run No. 95	WV	4%	8%	21%
Elk Creek Mine	CO	10%	20%	51%
Federal No. 2	WV	2%	3%	9%
American Eagle	WV	4%	9%	22%
	Average:	**12%**	**25%**	**62%**
	Range:	**2% - 59%**	**3% - 118%**	**9% - 296%**
VAM PROJECTS (oxidizing 50% VAM)				
McElroy Mine	WV	7%	15%	37%
Bailey Mine	PA	4%	7%	18%
Robinson Run No. 95	WV	4%	7%	19%
Federal No. 2	WV	6%	11%	28%
	Average:	**5%**	**10%**	**25%**
	Range:	**4% - 7%**	**7% - 15%**	**18% - 37%**

39 http://www.epa.gov/methane/cmop/resources/cashflow_model.html accessed 20 October 2013

40 EPA. 2009. Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006. EPA 430-K-04-003

41 EPA. 2009. Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006. EPA 430-K-04-003, and EPA. 2010. U.S. Underground Coal Mine Ventilation Air Methane Exhaust Characterization

costs in our analysis, which is too small to meaningfully affect our profit analysis.

Table 1 shows the results of these revised estimates in terms of the possible effects of carbon offset profits on mining profits.42 Using the assumptions described herein, we find that flaring projects can increase mining profits by an average of 12% for the eight modeled flaring projects, and VAM projects can increase mining profits by 5% for the four modeled VAM projects. These numbers would be higher if mine profit margins or MMC implementation costs are less than average, or if offsets prices exceed \$10 per tonne CO_2e. We continue to believe that the potential profit margins of these magnitudes for some MMC offsets projects are large enough to suggest that the Board should perform a more detailed analysis to better understand the effects of these profits on the production and use of coal.

Most sincerely,

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42 Since we do not have profit data for the specific mines we examine, we apply, in our analysis, a profit margin of 9.4%. This is the average profit margin over a five year period from 2008 to 2012 achieved by six U.S. coal mining companies: Alliance Resource Partners, Alpha Natural Resources, Arch Coal, CONSOL, Patriot Energy, and Walter Industries.42 These six companies are the only companies listed in the EPA 2009 report as owners of large gassy underground U.S. coal mines with publically available annual reports that focus their business primarily on coal mining.

APPENDIXES

1. Comment letter submitted to the Board on the proposed MMC protocol dated 22 August 2013

2. Comment letter submitted to the Board on the proposed MMC protocol dated 1 July 2013

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August 22, 2013

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RE: Comments on the Discussion Draft of the Proposed Compliance Offset Protocol Mine Methane Capture (MMC) Projects

Dear Ms. Bede:

First, we wish to sincerely thank the California Air Resources Board (the "Board") for the tremendous amount of work that went in to the release of the first informal draft of the proposed Mine Methane Capture compliance offsets protocol (the "Protocol"), and for the many opportunities to provide input on the Protocol. We also appreciate the Board's open responses to the questions we asked at the 19 August 2013 Offsets Workshop. Nevertheless, we are concerned that the Board has not responded to the main concerns expressed in our July 1 comment letter. Unless the problems with the current Protocol design raised below and in our earlier comment letter are addressed prior to finalizing it, we believe that substantial non-additional crediting of offsets will occur.

In response to the draft protocol and our interactions on August 19th, and based on our work as part of the Technical Working Group this summer, we offer the following input on the discussion draft Protocol:

1. We offer one suggested modification to the discussion draft protocol that we believe will simultaneously address two of the concerns we have raised. We suggest making projects that capture drainage methane from *new* underground mines and new major modifications to existing active underground mines ineligible under the Protocol. Doing so would avoid the Protocol's potential conflict with the Clean Air Act. It would also avoid the risk that new mines and wells that would have chosen to inject their mine methane into a pipeline would choose instead to flare their methane to earn the greater income from selling offsets credits at recent natural gas and allowance prices.

2. We provide thoughts on assessing and avoiding the crediting of non-additional methane capture at abandoned mines.

1. Projects that capture methane from drainage wells at new and major modifications to active underground coal mines should be considered ineligible under the Protocol

In our written comments emailed to you on July 1, and in our comments at the Offsets Workshop on August 19, we described two ways that the Protocol could result in an increase in emissions in addition to non-additional crediting.

First, the Protocol may undermine effective implementation of the Clean Air Act. Many new and major modifications to coal mines will need to receive Prevention of Significant Deterioration (PSD) permits for their emissions of greenhouse gas pollutants; no such permits have yet been written for coal mines; and the terms of those permits are determined by state-level agencies on a mine-by-mine basis. A tangible perverse incentive therefore exists for state agencies to determine that technologies which capture methane are not Best Available Control Technology (BACT) in order to allow mines within their borders to receive offsets payments to capture methane. This risk is particularly high at the present time before states have made their first BACT determinations for coal mines. A weak BACT determination for mines planning to sell offsets could have wider effect if weakened BACT standards are applied to other mines in the state. This potentially serious adverse consequence of the Protocol can be avoided by excluding drainage methane at new underground mines and at existing active underground mines that have undergone new major modification as a source of eligible methane capture under the Protocol.

A second potential perverse incentive that could result from the Protocol can be solved by the same exclusion. We recognize and appreciate that the Board has determined that pipeline injection is common practice at active underground mines with drainage wells and is therefore treated as non-additional. We also recognize that flaring or other destruction of methane from wells where injection had previously taken place is also ineligible for crediting under the Protocol. Our comments here apply again, as above, to newly installed drainage systems at *new* underground mines and *new* major modifications to existing active underground mines, where new mines and new major modifications are defined as those that start production *after* the adoption of the Protocol. At recent natural gas and carbon allowance prices, a mine operator would receive greater income from offsets for flaring methane from drainage wells than from selling that methane into a natural gas pipeline. This means that operators of new underground gassy mines or newly modified mines that would have otherwise chosen to inject their methane into a pipeline in the absence of the Protocol might instead choose to flare the methane to earn carbon credits. This would not only result in substantial non-additional crediting (methane destruction would be credited that would have happened through pipeline injection without the offsets protocol); it would also mean that methane is flared that would otherwise have been put to productive use.

Both of these issues are described in detail in our written comment letter from July 1, a copy of which is attached hereto.

Both of these risks are tangible, substantial, and largely avoidable. Both apply directly to new underground mines and major modification to existing active underground mines and so can be avoided by making drainage methane from new and majorly modified underground mines ineligible under the Protocol. Even if the Board decides to exclude these mines or mine expansions now, it can choose to include them in the future, after there is more clarity with regard to how BACT is determined for coal mines and if natural gas prices increase in a sustained manner.

2. The Board's assessment of the additionality of methane capture from abandoned mines

A) Methods for assessing common practice for mine methane capture at abandoned coal mines

At the August 19 Offsets Workshop we offered our understanding that, at present, around half of the methane from abandoned mines that could viably be captured, with or without carbon offsets, is already being captured. This mine methane capture is happening at 38 mines in the United States out of approximately 105 abandoned mines where methane capture is potentially viable according to an assessment by Ruby Canyon Engineering.[43]

These 38 mines with methane capture represent approximately one third of mines with an opportunity for methane capture (38 mines out of 105). While these 38 mines also represent a small fraction of the many thousands of abandoned mines in the country, this fact bears no relevance to an additionality determination for the Protocol. Assessments of BAU practice for the purpose of additionality testing should assess the potential influence of the Protocol compared to the BAU practice that could be credited under the Protocol. The Protocol will comply with the additionality requirements of AB 32 only if the total influence of the Protocol on emissions is far larger than any credited BAU practice, assuming that conservative reduction assessment methods can balance out crediting of such BAU practice.

The "denominator" used for BAU practice assessments should therefore be the pool of facilities where projects are actually feasible, rather than the pool of all abandoned mines in the country. For example, consider the inclusion of abandoned gold mines and copper mines in the denominator for assessing BAU mine methane capture from abandoned mines. Clearly these abandoned mines should not be included in this assessment because they do not release methane and therefore would not be able to participate in the Protocol even if they were included in the Protocol. Similarly, abandoned coal mines that that do not have characteristics that make them candidates for participation in the Protocol should also be excluded from the denominator. BAU assessments must evaluate current practice for the group of facilities that could potentially implement the practice in order to meaningfully assess the potential for non-additional crediting.

When assessing current practice related to mine methane capture, it is important to evaluate the proportion of methane that is being captured in addition to the proportion of mines where methane capture is already occurring. Mines with larger releases of methane are more likely to install mine methane capture technologies than mines with smaller releases. Further, from the perspective of atmospheric impacts, the total methane released, not the proportion of mines where that methane originates is the relevant consideration. For these reasons, an

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43 Ruby Canyon Engineering, Inc. (2013). *Abandoned Coal Mine Methane Offset Protocol: Background Information on Performance Standard and Additionality*. http://www.arb.ca.gov/cc/capandtrade/protocols/mmc/rce_amm_background.pdf (accessed 21 Aug 2013).

additionality assessment based on the quantity of methane already being captured more accurately reflects the risk of non-additional crediting than an assessment of a proportion of mines. Approximately one third of all methane from abandoned mines is being captured,[44] comprising approximately half of the methane released from the 105 abandoned mines that Ruby Canyon Engineering has identified as having the potential to feasibly implement mine methane capture.

B) Avoiding the non-additional crediting of BAU methane capture at abandoned mines

Given that a substantial proportion of feasible methane capture from abandoned mines is already occurring, it is necessary to take precautions to avoid crediting non-additional activities at abandoned mines. We believe that the Board faces similar considerations for methane emissions from abandoned mines as it does for pipeline injection of methane from drainage systems at active underground mines. We recommend that the Board perform an analysis of existing MMC projects at abandoned mines and trends in the characteristics of mines implementing such projects.

If that analysis shows that mines which capture methane when they are active are highly likely to continue capturing methane when they are abandoned, the Board should exclude this category of mine from participation in the Protocol because it will be likely that these projects will be non-additionality. In addition, if many of the 38 abandoned mines that currently capture methane were not capturing methane when they were active, the Board should examine the characteristics of these mines to determine other mine attributes have been predictive of the decision to capture methane.

In sum, while we appreciate the work that ARB staff has devoted to the development of the Protocol to date, we still believe that, due to the concerns raised above and in our previous comment letter, substantial non-additional crediting will occur under the Protocol as currently drafted.

Sincerely yours,

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44 *ibid*

Attachment: Stanford University comments to the Board on the proposed Mine Methane Capture Compliance Offsets Protocol from July 1, 2013

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July 1, 2013

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Mine Methane Capture
Compliance Offset Protocol

Dear Ms. Bede:

We respectfully submit these comments to the California Air Resources Board (the "Board") regarding the proposed Mine Methane Capture (MMC) Compliance Offset Protocol (the "Protocol"). We appreciate the opportunity to share our perspective in the informal Expert Technical Working Group process as the Board develops the draft Protocol in the coming months, and we thank the Board for engaging in a transparent process seeking input and expertise from a broad range of stakeholders. It is our intention to remain engaged in this process in order to assist the Board in developing a protocol that is technically, legally, and environmentally sound.

Based on our analysis of issues relating to the Protocol's relationship to existing laws, leakage risks, and additionality threshold criteria, we offer the following recommendations:

1. **If the Board sets eligibility thresholds for pipeline injection projects, the Board should also set eligibility thresholds for all other types of methane destruction projects that are at least as stringent as those for pipeline injection in order to avoid crediting non-additional activities and to avoid creating incentives to waste natural resources.**

2. **The Board should take proactive steps to prevent the Protocol from interfering with States' implementation of the Clean Air Act's New Source Review process and to avoid potential offset credit invalidations that may result from this interference.**

3. **The Board should examine and monitor the potential for emissions leakage resulting from increases in the profitability of coal mining due to revenues from offset credits under the Protocol.**

Attached to this letter, we provide three appendices that address issues related to the design of an MMC protocol. In Appendix A, we make recommendations regarding the Board's consideration of eligibility thresholds for pipeline injection and other project types at active underground mines. In Appendix B, we provide suggestions aimed at minimizing negative impacts of the protocol on the Clean Air Act's Prevention of Significant Deterioration ("PSD") permitting process for large emitters of greenhouse gases. In Appendix C, we examine the effect of offsets revenues on coal mining profits and the resultant potential for leakage emissions. These comments update and incorporate by reference, as applicable to the Board's planned Protocol, comments the Stanford Environmental Law Clinic previously submitted to the Climate Action Reserve ("CAR") regarding its Coal Mine Methane Project Protocol Version 2.0. We have included those comments here as Appendix D.

In Appendix A, we assess the use of thresholds for determining the eligibility of pipeline injection projects. The Board has discussed the possible use of eligibility thresholds for pipeline injection, but not for other project types that use drainage-mine methane. We urge the Board to set eligibility thresholds for all project types in order to avoid crediting non-additional activities. For example, if no eligibility threshold is set for flaring projects, but pipeline injection eligibility is restricted based on a threshold, then the activity of flaring drainage-well gas which exceeds the threshold could be (1) eligible for credits, but (2) non-additional. Flaring such gas would be non-additional because the gas could be profitably sold into a pipeline in the absence of any offset credits. Furthermore, crediting this non-additional activity would quite likely occur under plausible pricing scenarios. At today's natural gas prices (around $3.50 per MMBTU) and at a carbon offsets price of $15 per tCO_2e, destroying methane by flaring could generate more income for the mine than selling methane into a pipeline, inducing mine operators to opt for flaring rather than pipeline injection. So as not to incentivize mine owners to flare methane that they otherwise would have sold through the natural gas pipeline system, it is critical that eligibility thresholds be set for *all types of projects* that destroy drainage well methane at levels at least as stringent as those for pipeline injection. While the Board's Protocol could exclude flaring from eligibility at mines (or wells) where injection is already occurring, our concern lies in the financial incentives presented to a mine owner upon mine expansion, the drilling of new gob wells, or the development of a new underground mine.

Appendix B identifies two types of legal risks associated with the Protocol's relationship to the Clean Air Act. First, the existence of the Protocol creates an incentive for state permitting authorities to establish weaker standards for required Best Available Control Technology ("BACT") to control greenhouse gas emissions when they issue PSD permits for new mines or major modifications (expansions) of existing mines. In addition to directly compromising the implementation of the Clean Air Act and crediting projects that may otherwise have been legally required, the effects of these incentives may extend further if weakened control standards are applied to mines that do not implement offset projects. Second, if BACT determinations are made after offsets credits have been generated, there is a risk that those credits will be invalidated by a BACT determination that covers all or part of the technology implemented by the offsets project, triggering buyer liability. This, in turn, may trigger a wave of lawsuits among parties to the offsets transaction. In order to proactively avoid conflicts with the Clean Air Act and any resultant non-additional crediting or invalidation of credits, we recommend that the Board adopt scheduled updating procedures for MMC baselines, and that it exclude new or expanding mines from crediting. If the Board rejects this suggestion and elects to credit projects at these sites, it should, at minimum, authorize these projects only after any required PSD permitting process is complete and should set different, more conservative eligibility criteria for new and expanding mines to avoid influencing BACT determinations.

Appendix C demonstrates that offsets revenues for MMC projects can substantially improve the profits of companies engaged in underground coal mining. At carbon offset prices as low as $10 per tonne of carbon dioxide equivalent (tCO_2e), offset revenues can increase the profits of an underground coal mine with an average profit margin and level of gassiness by approximately 13%, and can increase mine profits by over 50% at the gassiest mines and at mines with relatively low profit margins. An offset price of $50/$tCO_2e$ would lead to an increase in profits of an average coal mine by around 66%, while more than doubling the profits of the most gassy mines and at mines with relatively low profit margins. We encourage the Board to perform its own examination of the possible leakage emissions that could be induced by the Protocol and to monitor this risk as energy prices and conditions change, methane capture technologies improve, and offsets prices increase. The leakage risk created from increasing mine profits means that the conservative choice of project eligibility criteria to prevent any non-additional projects from participating are especially crucial for this protocol.

In addition to the issues detailed in the appendices to this letter, we believe that the Board should consider other potentially important legal and technical issues in future discussions. For example, we note that Colorado Senate Bill 252,45 signed into law by Colorado Governor John Hickenlooper earlier this month, makes the capture and destruction of coal mine methane from active and inactive underground mines in Colorado eligible for consideration as a form of renewable energy under that State's Renewable Energy Standard. It is our understanding that under the additionality requirements of AB 32, the inclusion of mine methane capture in Colorado's renewable energy standard should preclude all Colorado-based mine methane projects from qualifying for compliance-grade offsets in California's market. Although the most obvious additionality problem arises with electricity projects that qualify under Colorado's renewable energy standard, the problem is significantly broader. Eligibility restrictions must apply to all project types because of the increased likelihood that drainage methane would be put to use in Colorado in the absence of a California offset protocol, and therefore its capture and use is even less likely to be additional. Further, if the Protocol were to allow for other project types to be credited (i.e., flaring, pipeline injection) but not electricity generation, California's offsets program could cause methane to be flared that otherwise would have been put to productive use generating electricity. This would happen if the profits generated from selling offsets from flaring exceeds the profits that would be generated by producing electricity without offsets revenues. This effect is discussed in detail in Appendix A with regard to pipeline injection. In order to avoid any ambiguity, **we urge the Board to explicitly consider the implications of including mine methane under state-level renewable energy standards or renewable portfolio standards on the additionality of mine methane capture projects in such states**.

In conclusion, we emphasize that the risks associated with an MMC Protocol go beyond crediting non-additional projects and over-estimating reductions from individual projects. The potential for an MMC Protocol to cause a weakening of BACT standards, to incentivize flaring over productive methane use, and to increase profits from coal mining could lead to an increase

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45 The bill's title is "An Act Concerning Measures to Increase Colorado's Renewable Energy Standard so as to Encourage the Deployment of Methane Capture Technologies,"

in emissions substantially greater than the credits generated. Our analyses find that these effects may be substantial. The Board should take affirmative steps to avoid these effects in the design of the Protocol, through applying conservative project eligibility criteria, developing safeguards against conflicts with the Clean Air Act, and monitoring these effects as technologies and conditions change over time.

While additionality is a statutory requirement under AB 32 for all offsets protocols, setting conservative criteria that avoids any non-additional crediting is especially crucial for a Mine Methane Capture protocol. The particular challenges of this Protocol—including the large sizes of individual offset projects, as well the complex interactions with federal law—recommend a heightened focus on setting robust standards. We therefore support the Board in its endeavor to develop conservative eligibility criteria that avoid crediting any non-additional pipeline injection projects. An equal level of rigor and conservativeness must also be applied to all project types covered under this Protocol.

We appreciate the opportunity to work with the Board as it develops this Protocol in the informal Expert Technical Working Group, and we look forward to our further discussions as the Protocol moves in to the formal regulatory process in the coming months.

Sincerely yours,

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APPENDIX A

Project Eligibility Thresholds

At the second meeting of the Potential MMC Compliance Offset Protocol Expert Technical Working Group (hereafter, "the Working Group") on May 21, 2013, the Working Group discussed the potential use of thresholds for determining the eligibility of pipeline injection projects for offset crediting from mines with drainage systems. These thresholds were based on the goal of ensuring that non-additional projects are not eligible to generate offset credits.

While the Working Group's discussion was limited to thresholds for the eligibility of pipeline injection projects, we believe that the Board must consider the potential interaction of thresholds across multiple project types. Setting eligibility thresholds in a piecemeal manner for only a subset of project types is likely to generate non-additional credits.

We offer the following recommendations, which are each explained in detail below:

1. **If the Board develops thresholds for eligibility of pipeline injection projects in its draft Protocol, then the Board should also develop eligibility thresholds that are at least as stringent for all other project types1 that destroy methane from drainage wells in order to avoid crediting non-additional projects.** Based on our analysis, we believe that such thresholds are necessary for the Protocol to meet the requirement under AB 32 that offsets credits be additional.

2. **We urge the Board to consider defining eligibility thresholds for flaring of mine methane that are more strict than for productive uses of the methane (e.g., pipeline injection, on-site consumption) when those productive uses are economically feasible with carbon credits.**

We support the Board in its endeavor to develop eligibility thresholds for pipeline injection that seek to ensure, to a very high level of confidence, that no non-additional mine methane capture projects will be eligible to generate offsets credits under the Protocol. Though our analysis here responds to a discussion about eligibility thresholds for pipeline injection, we encourage the Board to apply similar analyses of the risk of crediting non-additional credits as the Board considers the eligibility of other project types that may be covered under this Protocol, including all methane destruction from active underground mine venting, and methane destruction projects at abandoned underground mines, and surface mines.

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1 Other project types include flaring, other on-site destructive uses such as electricity generation, transportation fuel, heating fuel, thermal drying, or off-site destructive uses which do not involve sale into a natural gas pipeline network for distribution, such as the sale of methane for use as fuel at a nearby off-site facility.

1. In order to avoid crediting non-additional projects, the Board should set eligibility thresholds that are at least as stringent as those set for pipeline injection for all other project types that use drainage-well methane.

At its May 21 meeting, the Working Group discussed previously assessed criteria for setting eligibility thresholds for pipeline injection. These options included differentiating by mining method, methane liberation rate, well source, gas composition (percentage methane), gas quality (concentration of contaminants in gas), well-life, and distance from pipeline. Much of our discussion centered on setting thresholds using gas composition metrics (i.e., the percentage of methane).

It is our understanding that the rationale for using eligibility thresholds for pipeline injection is to avoid crediting non-additional projects. Pipeline injection of methane is common practice at mines with drainage systems; a majority of mines with drainage systems currently inject methane into pipelines.2 The threshold would thus be designed to establish eligibility for pipeline injection for a set of specific mine, well, or gas circumstances where injection *would not occur in the absence of the offset credit*, and thus, pipeline injection could be considered additional if the threshold criteria were met.

At its May 21st Working Group meeting, the Board did not discuss the application of eligibility thresholds for other methods of destroying methane, including flaring, or uses such as electricity generation and on-site heating. While pipeline injection of drained methane is common practice at a majority of mines with drainage systems in the United States, flaring is not currently in common practice,3 nor are other uses of methane from drainage wells.4 Since the rationale for the use of eligibility thresholds for pipeline injection is to assure that only additional projects are eligible for credits, it might seem straightforward to conclude that eligibility thresholds do not need to be applied to flaring or other destructive use project types. Because these activities are not currently common practice and are not economically profitable for most mines in the absence of offset credits, it could be assumed that these uses would be additional for any gas quality, well type, or other criteria, and thus there would be no reason to apply thresholds.

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2 In its analysis of gassy mines with drainage systems, the EPA found that as of 2006, 12 of 23 mines with drainage systems injected the majority of their mine methane into pipelines, and an additional four mines used at least some portion of their mine methane. Data from: EPA. 2009. Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006. EPA 430-K-04-003.

3 According to EPA, as of 2006, no active coal mines in the United States were currently engaged in flaring mine methane. From: EPA. 2009. Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006. EPA 430-K-04-003.

4 The use of methane for on-site power generation is common at mines in China, where projects have been developed under the Clean Development Mechanism. From: International Energy Agency. 2009. Methane in China: A Budding Asset with the Potential to Bloom: An Assessment of Technology, Policy and Financial Issues Relating to CMM in China, Based on Interviews Conducted at Coal Mines in Guizhou and Sichuan Provinces IEA Information Paper. Available at: http://www.iea.org/publications/freepublications/publication/name,15740,en.html

However, *not setting thresholds for flaring and other destructive use projects strongly risks crediting non-additional projects.* The reason for this relates to the financial incentives presented to a project developer by the circumstance in which a threshold is applied *only* to pipeline injection project eligibility.

Consider the following example. If the Board were to develop an eligibility threshold for pipeline injection which requires that mine gas must be less than 80% methane[5] to be eligible for pipeline injection (because it is presumed that lower quality gas would not be sold into a pipeline without the added financial benefit from offsets sales), and if no threshold were applied for flaring projects (because it is assumed that flaring would not otherwise occur in the absence of the offset credit), then mine methane sources with 80% methane or greater would be eligible only for flaring projects. However, in this example, the pipeline injection eligibility threshold presumes that injecting gas of this quality or greater can be profitable *without* the offset credit. Flaring drainage-well gas could therefore be (1) eligible for crediting, but (2) non-additional. This would also be true for credited on-site use projects that destroy methane that exceeds the threshold: such projects would generate credits for the destruction of methane that would likely have occurred in the absence of the Protocol. As the example above illustrates, the Board risks crediting non-additional projects if it does not promulgate eligibility thresholds for *all* project types, including flaring and other on-site destructive uses.

In the scenario described above, we have shown that there is a risk of crediting non-additional projects in the absence of thresholds for projects other than pipeline injection. Below we show that the risk is strong, due to the financial incentives that a project developer would face. Whether a project developer would opt to profitably inject the greater-than-80% methane content gas or would opt to flare it would depend on the relative value of the profits received from offset credits that would be received for the flaring project and the value of the profits received from selling the gas into a pipeline.

In comments previously submitted to the Climate Action Reserve ("CAR") regarding its Coal Mine Methane Project Protocol,[6] members of our team provided an analysis of the relative revenues from natural gas sales to pipelines and the generation of offset credits in the context of CAR's Protocol's eligibility rules for drained methane, which permitted flaring but prohibited pipeline injection. Under plausible pricing scenarios for both offset credits and natural gas, project developers will expect greater economic returns from flaring methane for offset credits than they would for selling the same methane as natural gas on the wholesale market (see Figure 1). At a carbon price of \$15/tCO_2e and at natural gas prices up to\$4.50/mmbtu or less (for comparison, as of December 2012 natural gas wellhead prices were around \$3.35/mmbtu[7]), a project developer would opt to flare rather than profitably inject mine methane.

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5 We use this number as a simple illustrative example only, not as an intended suggestion of a threshold value, nor as a recommendation of gas-quality metric based thresholds. The analysis below would apply to any or all thresholds.

6 Please see Appendix D.

7 Energy Information Administration, Natural Gas Prices, available at http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm. As of this writing, the most recent data for

Figure 1: Economic Value of Carbon Offsets Compared to Sale of Natural Gas

		CO2 price ($/tCO2-eq.)				Value of natural gas sales
		5	15	25	50	
Natural gas price ($/mmBTU)	2.5	$ (40.58)	$ 141.92	$ 324.42	$ 780.67	$ 131.83
	3.5	$ (93.31)	$ 89.19	$ 271.69	$ 727.94	$ 184.56
	4.5	$ (146.05)	$ 36.45	$ 218.95	$ 675.20	$ 237.30
	5.5	$ (198.78)	$ (16.28)	$ 166.22	$ 622.47	$ 290.03
	6.5	$ (251.51)	$ (69.01)	$ 113.49	$ 569.74	$ 342.76
	7.5	$ (304.24)	$ (121.74)	$ 60.76	$ 517.01	$ 395.49
Value of carbon offsets		$ 91.25	$ 273.75	$ 456.25	$ 912.50	

Each cell in the main table of Figure 1 shows the difference between the value of the carbon offset derived from flaring methane and the value of selling that methane into a pipeline, for a range of natural gas prices and offset prices, per metric ton of CO_2e. Positive numbers are highlighted and indicate that for the prices applicable in that cell, the carbon offset is more valuable than the direct sale of methane. Thus, under these conditions, a project developer will prefer to generate offset credits rather than sell captured methane into the pipeline network.8

In response to our earlier comments, CAR indicated that any project that has already been injecting into a pipeline would not be eligible for credits if it switched to flaring. The Board's Protocol could similarly exclude flaring from eligibility at mines (or wells) where injection is already occurring. This response has the effect of eliminating some, but not all risk. *We emphasize that our concern is more general and applies equally to the financial incentives presented to a mine owner upon mine expansion, the development of a new underground mine, or the drilling of new gob wells to drain methane from an active mining face.*

The fundamental problem is that an offset project developer that is eligible to receive offset credits for flaring drainage-well methane when pipeline injection is economically feasible but is not an eligible project type, will preferentially select flaring. This is because the value of the carbon offset is likely to be greater than the market value of natural gas (see Figure 1). If the Board were to set piecemeal eligibility thresholds for pipeline injection only, but not for flaring, the Board would create an incentive to flare gas that otherwise would have been injected into a pipeline, thus generating non-additional credits. We urge the Board to establish eligibility

wellhead natural gas prices are from December 2012. Notably for our analysis, natural gas wellhead prices have remained under $4.50/mmbtu since January 2011.

8 The Table in Figure 1 and its description are copied from the previous comment letter submitted to the Climate Action Reserve. The full comment letter is included as Appendix D.

thresholds for flaring and other methane use projects that are at least as stringent as those established for pipeline injection.

We recognize that applying conservative eligibility criteria to flaring may miss opportunities to reduce emissions cost effectively through flaring mine methane. However, from the perspective of achieving California's emissions target, we view the risks associated with inducing the flaring of methane that would otherwise have been injected into a pipeline as far greater. As a compliance-grade offsets program, the credits generated must meet AB 32's requirement that all offset credits are additional. Thus, to avoid the strong risk of crediting non-additional activities outlined above, we urge the Board to adopt eligibility thresholds for all project types that use drainage well methane.

2. The Board should consider defining eligibility thresholds for flaring of mine methane that are more strict than for productive uses of the methane (e.g., pipeline injection, on-site consumption) when those productive uses are both additional and economically feasible with carbon credits to avoid incentivizing the unproductive use of this gas.

In Section 1, we urge the Board to set eligibility thresholds for flaring and on-site destructive use projects that are as least as stringent as those set for pipeline injection projects, in order to meet the statutory requirements of AB 32 that it avoid generating non-additional credits. In Section 2, we present an observation that refines our recommendation in Section 1. Setting identical eligibility threshold levels for flaring, other on-site destructive uses, and pipeline injection would address our primary concerns regarding crediting non-additional projects. However, the incentives resulting from setting such identical thresholds for all project types could still incentivize the flaring of methane that would otherwise have been put to productive use in the economy. Specifically, we note that such a Protocol could incentivize non-productive uses of methane (i.e., flaring) when productive uses (e.g., pipeline injection, electricity generation, vehicle gas) remain economically feasible with offset credits.

The decision to flare or to inject drainage methane that would otherwise have been vented would be determined by the relative profits from pipeline injection and flaring because the mine would receive offset credits from either project type. In order to build a pipeline project, the mine would have to construct pipeline infrastructure and potentially upgrade the quality of the gas by removing nitrogen or other contaminants. In contrast, flaring would likely require fewer up-front costs, but would not generate revenues from natural gas sales. When revenues generated from the sale of the gas into the pipeline do not make-up for the difference in relative costs of the two project types, under circumstances where identical thresholds are applied to injection and flaring projects, the project developer would prefer to flare the methane. This would be the case even if the operator could profitably inject the same natural resource into a pipeline network with offsets credits.

While there is no legal requirement for a Protocol to avoid creating such incentives under AB 32, as both project types would be additional in the above example, we bring this issue to the Board's attention because we believe that the Board may wish to draft a Protocol that avoids incentivizing the flaring of methane that could otherwise be put to productive use in the economy, for two reasons. First, the productive use of this methane would displace an equivalent amount of methane that would otherwise be consumed elsewhere within the pipeline, and thus the productive use would avoid emissions elsewhere in the economy. Secondly, setting thresholds so as not to incentivize flaring when productive-uses are feasible avoids having the Protocol encourage an activity which may be perceived as the waste of a valuable natural resource. For these reasons, we urge the Board to consider setting more stringent thresholds for flaring projects than for productive-use projects.

3. Recommendations

Based on our analysis, we recommend that, in order to minimize the risk of crediting non-additional emissions reductions, the Board should:

1. Set eligibility thresholds for all projects types that use drainage-well methane (e.g., pipeline injection, flaring, electricity generation, and other on-site uses);
2. Set eligibility thresholds for flaring and other destructive uses that are at least as stringent as the eligibility thresholds set for pipeline injection.

Further, we recommend that, in order to avoid incentivizing the flaring of methane that might otherwise have been put to productive use, the Board should:

3. Set eligibility thresholds so that flaring projects are only eligible when productive uses (e.g., pipeline injection, on-site consumption) are unlikely to be effectively supported by offsets credits.

Finally, as also discussed in Appendix B, which addresses the need to regularly revisit the Protocol's approach to eligibility, given the evolution of regulation of mine methane emissions under the Clean Air Act, we urge the Board to consider establishing a timeline schedule for regularly revisiting eligibility threshold criteria for pipeline injection and other project types which destroy drainage-well methane. Given the relatively quick pace at which methane capture technologies are developing, revisiting thresholds criteria according a schedule established in the Protocol would help ensure that, in practice, eligibility thresholds are not inducing the crediting of non-additional projects.

APPENDIX B

Legal and Policy Interactions Between the MMC Protocol and the Clean Air Act's New Source Review Program for Greenhouse Gases

Two types of legal risk exist if the Protocol creates eligibility for projects at new mines or projects associated with mine expansions that increase emissions by 75,000 metric tons of carbon dioxide equivalent per year. First, the existence of the Protocol creates a perverse incentive for state permitting agencies to establish weaker standards than they otherwise might for required Best Available Control Technology ("BACT") to control emissions when the states issue Prevention of Significant Deterioration ("PSD") permits for new mines or major modifications of existing mines. In addition to potentially compromising the implementation of the Clean Air Act and risking crediting activities that would have occurred in the absence of the Protocol, this incentive could also further undermine the climate benefits of the Protocol if these same weakened permitting standards are applied to mines that do not implement offset projects.

Second, there is a risk that some BACT determinations could invalidate offset credits if the Board is not careful to credit only projects that have already fully complied with all New Source Review ("NSR") requirements. Many coal mines will be subject to the NSR permitting process upon expansion or when newly constructed. Mines that opened or made major modifications since 2011 may already be required to apply for PSD permits because of their greenhouse gas emissions ("GHG"), but none have yet gone through the application process.[1] Further, no state has yet defined GHG BACT for any such permit. There is, therefore, a risk that offsets may be invalidated if projects are certified for offsets before legally required BACT determinations have been made. For example, a BACT determination requiring methane mitigation measures for mines that are also generating offsets credits may, in some cases, invalidate those credits. But invalidation is no simple matter. Either litigation or individual mine regulation decisions could cause the invalidation of credits, but both of these processes can span months or years. In turn, invalidation and the resultant buyer liability may result in expensive and complex litigation for participants in the offsets transaction, including the Board.

Given these risks, the Board should take particular care to address any such potential conflicts now, at the outset of the development of the protocols. The Board's response to these risks should take a proactive approach above and beyond the level of concern expressed in the Climate Action Reserve draft protocol. We recommend here two measures that can help to mitigate these risks. First, the Board should include in the Protocol a schedule of time or event-based thresholds that will trigger a re-assessment of protocol baseline conditions. These periodic reassessments will allow for recalibration of the Protocol in response to BACT determinations. Second, the Board should consider excluding new mines and expanding mines engaged in major modifications from eligibility for offsets credits. This approach would eliminate the risk of

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1 Each PSD permit requires a BACT determination. The U.S. Environmental Protection Agency, Clean Air Technology Center - RACT/BACT/LAER Clearinghouse, does not list any greenhouse gas BACT determinations for coal mines. See http://cfpub.epa.gov/rblc/index.cfm?action=Search.BasicSearch&lang=eg, accessed 27 July 2013.

conflict between offsets generated under the Protocol and Clean Air Act BACT requirements. If instead, the Board decides to allow offset projects at mines potentially subject to BACT, it should do so only after developing additionality analysis techniques specifically tailored to avoid conflict with BACT determinations. In addition, the Board should require that all MMC project developers attest in writing that the mine is in compliance with all PSD permitting requirements and certify any offsets generated at these sites only after the Board has independently assessed the baseline conditions and after any required BACT determinations have been made. In addition to these measures, the Board should establish monitoring and reporting requirements to ensure that any required BACT has been implemented and remains fully operational.

These informal comments update and incorporate by reference, as applicable to the Board's planned Protocol, comments previously submitted to the Climate Action Reserve ("CAR") regarding its Coal Mine Methane Project Protocol Version 2.0 (attached hereto as "Appendix D"). In the context of developing a compliance-grade offset protocol for California's carbon market, which may serve as a model for other offsets programs in North American and around the world, it is crucial that the protocol avoid legal and policy conflicts with federal law.

1. The Protocol's complex relationship with the Prevention of Significant Deterioration program under the Clean Air Act raises serious concerns about the ability of the Protocol to produce real and additional emission reductions.

As of 2011, large new and expanded coal mines are required to obtain PSD permits in order to comply with the Clean Air Act. New Source Review ("NSR") under the Clean Air Act applies to new or major modifications of mines.2 The U.S. Environmental Protection Agency ("EPA"), through its Tailoring Rule, currently interprets the NSR provisions of the Clean Air Act to require the establishment of greenhouse gas emissions thresholds in PSD permits for the largest emitters.3 Under the Tailoring Rule, new underground mines that emit at least 100,000 tons CO_2e per year and modifications to underground mines that increase the mine's emissions by at least 75,000 tons CO_2e per year are required to obtain a PSD permit.4

The PSD program puts substantially all of the permitting authority in the hands of state environmental agencies. PSD permits are generally issued by state agencies with delegated

2 See generally 42 U.S.C. §§ 7470–79.

3 See 40 C.F.R. 52.21(b)(1)(i); . *Coalition for Responsible Regulation v. EPA*, 684 F.3d 102, 134-35 (D.C. Cir. 2012), *reh'g en banc denied* (D.C. Cir. Dec. 20, 2012), *petition for cert. filed* (U.S. Apr. 17, 2013) (No. 12-1253).

4 40 C.F.R. 52.21(b)(49)(b)(iii–v). While it is not certain how many new mines are likely to be permitted in coming years, if past trends are any indication, a substantial portion of any new mines are likely to meet or exceed this threshold. Of 75 reporting underground coal mining facilities, 33 emitted 75,000 tons or more CO2e in that year. U.S. ENVIRONMENTAL PROTECTION AGENCY, 2011 GREENHOUSE GAS EMISSIONS FROM LARGE FACILITIES, *available at* http://ghgdata.epa.gov/ghgp/main.do.

implementation responsibility.5 In order to obtain a PSD permit, regulated sources must demonstrate to state regulators that they employ BACT to mitigate emissions. But what specifically constitutes BACT is determined by the state permitting agency on the basis of its assessment of technical and economic feasibility of available pollution reduction measures.6 EPA has extremely limited authority to review these state agency findings unless they are unreasonable or unsupported by the evidentiary record. In short, state environmental agencies retain substantial discretionary authority to determine BACT in the context of PSD permits.7

A. The Protocol creates a tangible perverse incentive that encourages state-level regulators to make weak BACT determinations.

The availability of offset credits for methane emission reduction measures will increase political pressure on state regulators who make GHG BACT determinations to require minimal or no controls in order to retain legal additionality for MMC projects which benefit industry in their states. State agencies make determinations as to what constitutes GHG BACT on a case-by-case basis, taking into account available techniques and technologies for emissions control, as well as technical and economic considerations.8 The measures a mine might employ in order to create offsets under the MMC protocol are among the measures an agency would consider for any mine requesting a PSD permit. This means that when a state makes a GHG BACT determination for an individual mine applying for a PSD permit, that state agency must decide whether the particular mine is required to capture and combust methane that would otherwise be released from the mine. If a mine must mitigate its methane emissions in order to comply with the terms of its PSD permit, this same mitigation could not generate offsets credits under the Protocol. But if a state does not require methane capture as BACT for the PSD permit, the mine may generate offsets credits from methane capture, if it chooses to do so. The state and the mine therefore have every incentive to find methane mitigation infeasible, even where the technology is readily available and not cost-prohibitive: both the mine operators and the state permitting agency would rather have a third party pay for the emissions reductions than to have them go uncompensated as a legal requirement. As explained in prior comments to CAR (see Appendix D), even the possibility or appearance of this perverse incentive can affect the integrity of the protocol. This concern is even more significant for California's efforts to establish a legally binding compliance mechanism.

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5 States that do not have an approved NSR State Implementation Plan or that implement a plan developed by the federal EPA rely to varying degrees upon the federal EPA to administer this portion of the Clean Air Act. All but five states, the District of Columbia, Puerto Rico, and the Virgin Islands have some version of a State Implementation Plan. See U.S. ENVIRONMENTAL PROTECTION AGENCY, NEW SOURCE REVIEW, Where You Live, *available at* http://www.epa.gov/NSR/where.html.

6 See 42 U.S.C. § 7479(3). In some states the BACT determinations may be made by or implemented by the federal EPA, rather than the state permitting agency. See n. 4, *supra*.

7 *Alaska Dep't Envtl. Conservation v. Envtl. Prot. Agency*, 540 U.S. 461 (2004). See also Appendix D, 2–3.

8 See 42 U.S.C. § 7479(3).

CAR responded to this concern only with the assurance that it would "track developments under the CAA and BACT determinations made at the state level will inform updates to the protocol's additionality tests over time."9 This approach is unsuitable for the Board's compliance-grade protocol, which, as a matter of law, may only sanction credits that are real and additional.

While all offset protocols present some risk of undermining other enforcement regimes, the risk under the MMC Protocol is tangible and immediate. Here, there is an existing federal law implemented by state agencies with considerable discretion as to the stringency of applied standards and a strong local constituency with a financial stake in the determinations. Because the perverse incentive would affect agencies in other states, California's actions could create serious consequences for the implementation of the Clean Air Act that neither California nor EPA, given its limited authority to review state BACT determinations, could effectively remedy.10

If the Board proceeds with a protocol that does not address the PSD conflicts that we identify here, weak GHG BACT determinations may occur in key states that could thereby lock-in a deflated legal baseline for credits under the Protocol and hinder stricter GHG BACT determinations more broadly. We emphasize that this outcome would affect methane emissions at both mines where MMC Protocol projects are implemented and those where they are not.

B. BACT determinations that require methane reductions may invalidate issued offsets, triggering buyer liability and litigation risks.

If the Board were to credit reductions from mine methane control measures, and a subsequent BACT determination includes methane control measures, those credits could be subject to invalidation. When a permitting agency issues a PSD permit, it is required to consider both the technical and economic availability of emissions reductions measures. If, in making this determination, a state reaches a BACT determination that imposes strong GHG limits – rather than succumbing to the incentive to weaken permitting standards as described in section A above – certain otherwise eligible emissions reductions may no longer be creditable under the Protocol. If a PSD permit finds that the project activities constitute BACT, and are therefore legally required, the project could no longer be considered legally additional under the Protocol, and buyer liability would be triggered. In this situation, we are concerned that the triggering of buyer liability might affect investor confidence in this project type and/or the ARB offsets program more generally and that the Board could face protracted litigation.

At particular risk of invalidation are offsets issued for the term between the effective date of the BACT determination (which could precede the date the permit is issued if the mine has failed to apply for the permit in a timely manner) and the end of the reporting period during

9 Climate Action Reserve, Summary of Comments and Responses – Coal Mine Methane Project Protocol Version 2.0, 3.4.4.1 (p. 3), http://www.climateactionreserve.org/wp-content/uploads/2009/10/Summary_of_Comments_and_Responses_CMM_Project_Protocol_V2.0.pdf

10 *Alaska Dep't Envtl. Conservation v. Envtl. Prot. Agency*, 540 U.S. 461 (2004).

which the effective date occurs. Depending on the circumstances of the PSD program, the Board's determination may be more complicated, and even reaching a clear understanding of which credits are valid and invalid may be extremely difficult to establish.

Furthermore, in a situation where a state BACT determination invalidates some or all of a project's credits under the Protocol, it will not necessarily be clear at what point those legal obligations invalidated the credits. For example, if a mine did not apply for a PSD permit, but a court determined that one was needed, does a subsequent BACT determination that sets a performance standard above the MMC invalidate all credits the project generated, or just the ones issued after the court decision? This complexity increases the uncertainty created by the interaction between the Clean Air Act and the MMC protocol.

2. The Board Should Adopt Measures to Affirmatively Address Conflicts with the Clean Air Act

In order to reduce the risks described above, the Board should adopt two measures that would serve to address both the regulatory incentive problem and any resultant uncertainty around potential invalidation. First, the Board should establish a schedule of dates and/or triggering events for re-evaluation of the legal additionality baseline under the protocol. The schedule should anticipate ongoing GHG BACT determinations, changing market conditions, and recent technical developments; it should also indicate the Board's willingness to examine differences in GHG BACT determinations among different state permitting agencies for similar mines in evaluating additionality under the MMC protocol.

Second, the Board should adopt separate offsets eligibility criteria for projects at existing mines and projects at mines that may arguably be considered new or major modifications for the purposes of NSR. In these separate procedures for new or expanded mines, MMC projects at new mines or new emissions associated with major expansions of existing mines should remain ineligible for crediting until there is greater clarity about how NSR will be applied to mines, including specifically how BACT for GHG emissions will be determined. At a minimum, if the Board does consider crediting MMC projects at new or newly expanded mines, the Board should set more conservative eligibility criteria for these mines to avoid conflict with BACT determinations. In addition, the Board should require project developers to attest in writing that the mine is in compliance with all PSD permitting requirements, and that any even arguably needed BACT determinations are finalized prior to establishing the baseline emissions for the project. These latter requirements, however, only address the risk of invalidation and would not avoid regulatory incentives to weaken GHG BACT determinations.

A. The Board should adopt scheduled updating procedures to MMC baselines.

As we suggested to CAR, by establishing a clear schedule of dates and/or triggering events for re-evaluating the protocol legal and technical baselines, the Board will reduce the strength of perverse incentives to create long-term distortions in both the offsets market and Clean Air Act implementation. This measure will send a clear signal that, notwithstanding any attempts to manipulate additionality determination through artificially weak GHG BACT determinations, the Board will not allow these determinations to set an additionality baseline either unilaterally or for an extended and indefinite time. A triggering event could be a particular event, such as the issuance of the fifth PSD permit for mine methane emissions, or a certain level of market penetration of a methane reduction technology. Alternatively, the Board could use a time horizon. Moreover, unless the Board plans to monitor every relevant GHG BACT determination on its own, we suggest that it explicitly invite interested parties to identify relevant problems as the PSD program gains experience under the Tailoring Rule, reviewing the legal additionality standard at its discretion.

One of the principal benefits of this adaptive management feature would be that regulated entities and state regulators outside of California would have clear guidance regarding the conditions under which the baselines will be adjusted. As a result, market participants could invest with greater certainty, and the temptation for state regulators to game the GHG BACT process would be reduced. While this measure would not eliminate risk of states making GHG BACT determinations that are one generation behind the Protocol's latest baseline adjustment, this form of adaptive management would limit the long-term lock-in of weak GHG BACT in states where financial incentives are oriented towards maximizing revenues from offsets for coal and other mines. It would also help to maintain the integrity of the protocol by reducing the perception that the protocol creates perverse incentives that might undermine the environmental benefits of mine methane reduction offsets.

B. The Board should refrain from crediting projects at arguably new mines or major modifications of existing mines. If it chooses to credit projects at these sites, it should do so only after ensuring that credited offsets will not be retroactively invalidated. Such projects should be required to meet more conservative eligibility criteria that avoid conflict with GHG BACT determinations.

Given the very real influence that California's MMC Protocol may have on GHG BACT determinations for coal mines, the Board should avoid possible conflicts with the Clean Air Act by refraining from crediting projects at mines that are even arguably new or major modifications of existing mines for the purposes of NSR until several PSD permits have been issued in multiple states. Once it is clearer how states will make GHG BACT determinations for coal mines, the Board will be better able to identify eligibility criteria that would avoid crediting projects which might also have been considered GHG BACT in the absence of the Protocol.

If the Board rejects this position and instead elects to approve any projects from new mines or mine modifications large enough to raise the possibility that a PSD permit may be required, it should be particularly conservative in determining eligibility criteria. Eligibility criteria should be established for these mines that conservatively avoids crediting any activity that may be considered BACT. In any event, no credits should be issued for these projects until all arguably required PSD permitting procedures are complete and any measures required by these permits are implemented and verified. To operationalize this requirement, MMC Protocol project developers should be required to attest to such completion as a part of their project registration.

Even after there is greater clarity about how GHG BACT is being applied to coal mines, the Board should still maintain separate eligibility criteria for projects at mines that may arguably be subject to NSR. By adopting separate baseline determination procedures for projects at new mines and for major modifications, the Board can assess the GHG BACT determination made for each mine and determine whether the mandated controls reflect an additionality threshold consistent with the Board's assessment of the state of the industry. In this way, the Board can simultaneously eliminate the risk that a particular GHG BACT determination might invalidate existing offsets and establish a baseline that will counteract the effects of any artificially weakened GHG BACT determinations that might arise in response to the protocol.

APPENDIX C

The Effects of a Mine Methane Capture Protocol on Coal Mining Profits

At the first Potential Mine Methane Capture (MMC) Compliance Offset Protocol Technical Working Group meeting on May 3rd, 2013, we mentioned that we were analyzing the potential effects of revenues from offset credits generated by coal mine methane destruction on the on coal mining operations and the risk of leakage emissions resulting from this new revenue source. Below are the results of this analysis.

1. Summary of Results

We find that offsets revenues from MMC projects can substantially improve the profits of companies engaged in underground coal mining. At carbon offset prices as low as $10 per tonne of carbon dioxide equivalent (tCO_2e), offset revenues can increase the profits of an underground coal mine with an average profit margin and level of gassiness by 13%, and can increase mine profits by over 50% at the gassiest mines and at mines with relatively low profit margins. An offset price of $50/$tCO_2e$ would lead to an increase in profits of an average coal mine by 66%, while more than doubling the profits of the most gassy mines and of mines with relatively low profit margins. Further, income from offsets would also provide coal mining companies with some buffer against annual variability of revenues from coal sales, such as results from relatively common temporary mine closures.1 Increases in coal mine profits from offsets would come at a time when coal and natural gas are in close competition as fuels for electricity generation; small differences in fuel prices can affect the marginal dispatch order of power plants, and in turn, their associated greenhouse emissions. This set of conditions suggest that by substantially increasing the profits of some coal mines, the MMC protocol has the potential to induce leakage in the form of increased emissions from continued and expanded mining operations.

TABLE 1: OFFSETS REVENUES AS % OF COAL MINING PROFITS

For 20 hypothetical offsets projects
assuming a 9.4% coal mining profit margin without offsets

Mine	State	Offsets project	at an offsets price of: $10	$20	$50
McElroy Mine	WV	100% drained	5%	10%	26%
		50% VAM	14%	29%	71%
Bailey Mine	PA	100% drained	8%	16%	39%
		50% VAM	9%	18%	46%
San Juan South	NM	100% drained	13%	27%	67%
		50% VAM	10%	20%	51%
West Elk Mine	CO	100% drained	64%	129%	322%
		50% VAM	32%	64%	161%
Robinson Run No. 95	WV	100% drained	7%	14%	35%
		50% VAM	8%	16%	41%
Elk Creek Mine	CO	100% drained	16%	32%	79%
		50% VAM	23%	47%	117%
Federal No. 2	WV	100% drained	5%	10%	25%
		50% VAM	15%	29%	73%
Bowie No. 2	CO	100% drained	5%	10%	24%
		50% VAM	7%	14%	36%
Dugout Canyon	UT	100% drained	3%	6%	16%
		50% VAM	5%	11%	26%
American Eagle	WV	100% drained	7%	13%	34%
		50% VAM	5%	10%	25%
		Average:	**13%**	**26%**	**66%**
		Range:	**3% - 64%**	**6% - 129%**	**16% - 322%**

These results derive from an analysis of the revenues that could be generated from mine methane capture projects at the ten gassy active

1 Mines continue to emit methane when active mining operations have been suspended.

underground mines that the EPA has identified as having drainage wells, but where mine operators were venting (i.e., not destroying) either all or nearly all mine methane emissions in 2006.2 For these ten mines, we analyze the potential offsets revenues from twenty hypothetical projects: the capture of 100% of drainage/gob methane emissions from each of the ten mines, and the capture of 50% of ventilation air methane emissions ("VAM") from each of the ten mines. We use offsets prices of \$10, \$20 and \$50 per tCO_2e to examine the potential for carbon offsets revenues to meaningfully improve the economics of underground coal mining. Since this analysis uses average state-level coal prices, average mining profit margins, and mine-specific coal production and methane emissions from a single year (2006), this analysis is meant to provide insight into the range of financial benefits that could be derived from MMC offsets projects at active underground coal mines, rather than an assessment of the financial benefits of specific methane capture projects at specific mines. The assumptions used in this analysis are described below in the "Details of the Analysis" section.

Table 1 shows the potential effects on coal mine profits from the revenues for offsets generated by the twenty mine methane capture projects analyzed. We find the potential for large profit increases from MMC offsets. Profit margins vary dramatically among companies and over time. The impact that offsets revenues could have on the profits of mines with lower-than-average profit margins, which are also those mines most at risk of closure, would be larger than the results given here.

We did not perform a full analysis of the emissions leakage that might result from an increase in mine profits from offsets. Determining the extent to which increases in mining profits may cause an increase in coal use from individual mines is substantially more complex and involved than the analysis provided herein. Increasing the profitability of gassy mines generating offsets credits under the Protocol may enable some mines to expand operations or avoid closure. If these gassy mines displace coal that otherwise would have been produced by less gassy mines, the Protocol could result in a large increase in methane emissions that is unaccounted for by the Protocol. A second avenue by which increased coal mining profits can cause emissions leakage is if the increased profits result in lowered coal prices. This is of particular concern under present conditions, considering that reductions in natural gas prices over the last several years have lead to a substantial shift from coal to natural gas as fuels used to generate electricity in the United States.3 We encourage the Board to perform its own examination of the possible leakage emissions that could be induced by the increase in mining profits shown here and to monitor this risk as energy prices and conditions change, methane capture technologies improve, and offsets prices increase.

The leakage risk created by choosing to credit emissions reduction projects at facilities that produce coal, a fuel responsible for a large portion of the country's greenhouse gas

2 EPA. 2009. Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006. EPA 430-K-04-003

3 Pratson, L. F., D. Haerer & D. Patiño-Echeverri (2013) Fuel Prices, Emission Standards, and Generation Costs for Coal vs Natural Gas Power Plants. *Environental Science & Technology*, 4926−4933

emissions, suggests that conservative project eligibility criteria that avoid crediting any non-additional activity is especially crucial for this Protocol. Since the main costs of a non-additional offsets projects are monitoring and verification (technology costs of the offsets project are effectively zero since the technology would have been implemented anyway), revenues from non-additional projects go directly into profits. Until the leakage risk is better understood, it is best to take extra precaution to avoid windfall profits to non-additional activities by establishing conservative eligibility criteria.

2. Details of the Analysis

We estimate coal revenues using coal prices from underground coal mines by state and by type of coal (steam or metallurgical) obtained from the Energy Information Administration's (EIA's) 2012 Annual Coal Report averaged over 2010-2011.4 For the quantities of coal mined, we use data from 2006, compiled in the EPA 2009 report on mine methane emissions.[2]

Since we do not have profit data for the ten specific mines we examine, we apply, in our analysis, a profit margin of 9.4%. This is the average profit margin over a five year period from 2008 to 2012 achieved by six U.S. coal mining companies: Alliance Resource Partners, Alpha Natural Resources, Arch Coal, CONSOL, Patriot Energy, and Walter Industries.5 These six companies are the only companies listed in the EPA 2009 report as owners of large gassy underground U.S. coal mines with publically available annual reports that focus their business primarily on coal mining.

To compare offsets revenues with coal mining profits, we assume very low offsets project implementation costs compared to offsets revenues, such that practically all of the calculated revenues go directly into profits. This would be true for non-additional projects, for which the main costs are monitoring and verification, and for technologies with implementation costs well below offsets income, as would likely be the case for flaring projects.6 The effects of carbon offsets on mining profits would be less significant for offsets projects with costs that are closer in size to the revenues generated by the offsets project.

Table 2 provides information about the ten mines and twenty projects analyzed, including estimates of their revenues from offsets and coal sales based on the assumptions described above.

4 U.S. Energy Information Administration. 2012. Annual Coal Report 2011. Washington, DC. Table 28. Average sales price of coal by State and mine type, 2011, 2010, http://www.eia.gov/coal/annual/.

5 Profit margins between 2008 to 2012 taken from these companies' annual reports, are as follows: Alliance Resource Partners: 17.0%, Alpha Natural Resources: 2.6%; Arch Coal: 8.0% (we use a zero profit margin during 2012 when Arch Coal had negative profits); CONSOL: 9.1%; Patriot Energy: 3.0% (we use a zero profit margin during 2010 to 2012 when Patriot Energy had negative profits); Walter Industries: 16.6% (we use a zero profit margin during 2012 when Walter Industries had negative profits).

6 Ranges of capital and operating costs for CMM flaring projects are documented in the US EPA Coal Mine Methane Project Cash Flow Model, http://www.epa.gov/cmop/resources/cashflow_model.html (accessed 11 June 2013)

The last columns of this table shows offsets revenues as a percentage of coal sales revenues for various offsets prices.

The maximum values of offsets revenues as a percentage of coal sales revenues shown in this table are from a gassy mine that was closed for several months in 2006 (West Elk Mine). The temporary closure of this mine resulted in relatively high methane emission per ton of coal produced, since methane continues to vent even when mining operations have been paused. While this mine produces methane at substantially higher rates per ton of coal produced than the other nine mines analyzed, temporary mine closures are common, and EPA's 2009 report which provides data on fifty active gassy underground mines shows that these levels of methane emissions per ton coal produced are not uncommon and can be much higher.

We would be more than happy to provide the spreadsheet used in this analysis.

Table 2: Mine methane capture carbon offest revenues compared with gross coal sales revenues

		COAL REVENUES				OFFSETS REVENUES					OFFSETS REVENUES AS % OF GROSS COAL REVENUES		
								Revenues (mill$) at an offsets price of:			at an offsets price of:		
Mine	State	Coal mined in 2006 (mill tons) *(1)*	Coal type: steam or metallurgical *(1)*	$ / ton coal *(2)*	Revenues from coal sales (mill$)	Offsets projects assessed	Methane that would be captured (MTCO2e) *(1)*	$10	$20	$50	$10	$20	$50
McElroy Mine	WV	10.5	Steam	$58.11	$610.10	100% drained	0.29	$2.94	$5.88	$14.71	0.5%	1.0%	2.4%
						50% VAM	0.82	$8.19	$16.37	$40.93	1.3%	2.7%	6.7%
Bailey Mine	PA	10.2	Steam *(4)*	$54.78	$558.71	100% drained	0.41	$4.09	$8.19	$20.46	0.7%	1.5%	3.7%
						50% VAM	0.48	$4.80	$9.59	$23.98	0.9%	1.7%	4.3%
San Juan South	NM	7.0	Steam	$37.44	$262.08	100% drained	0.33	$3.33	$6.65	$16.63	1.3%	2.5%	6.3%
						50% VAM	0.25	$2.5	$5.0	$12.5	1.0%	1.9%	4.8%
West Elk Mine	CO	6.0	Steam	$32.02	$192.09	100% drained	1.16	$11.6	$23.3	$58.2	6.1%	12.1%	30.3%
						50% VAM	0.58	$5.8	$11.6	$29.1	3.0%	6.1%	15.1%
Robinson Run No. 95	WV	5.7	Steam	$58.11	$331.20	100% drained	0.22	$2.2	$4.3	$10.9	0.7%	1.3%	3.3%
						50% VAM	0.26	$2.6	$5.1	$12.8	0.8%	1.5%	3.9%
Elk Creek Mine *(3)*	CO	5.1	Steam	$32.02	$163.28	100% drained	0.24	$2.4	$4.9	$12.2	1.5%	3.0%	7.4%
						50% VAM	0.36	$3.6	$7.2	$17.9	2.2%	4.4%	11.0%
Federal No. 2	WV	4.6	Steam	$58.11	$267.28	100% drained	0.13	$1.3	$2.6	$6.4	0.5%	1.0%	2.4%
						50% VAM	0.36	$3.6	$7.3	$18.2	1.4%	2.7%	6.8%
Bowie No. 2	CO	4.4	Steam	$32.02	$140.87	100% drained	0.06	$0.6	$1.3	$3.2	0.5%	0.9%	2.3%
						50% VAM	0.10	$1.0	$1.9	$4.8	0.7%	1.4%	3.4%
Dugout Canyon	UT	4.4	Steam	$38.13	$167.77	100% drained	0.05	$0.5	$1.0	$2.6	0.3%	0.6%	1.5%
						50% VAM	0.08	$0.8	$1.7	$4.2	0.5%	1.0%	2.5%
American Eagle	WV	2.4	Both *(5)*	$169.02	$405.64	100% drained	0.26	$2.6	$5.1	$12.8	0.6%	1.3%	3.2%
						50% VAM	0.19	$1.9	$3.8	$9.6	0.5%	0.9%	2.4%
										Average:	**1.2%**	**2.5%**	**6.2%**
										Range:	**0.3% - 6.1%**	**0.6% - 12.1%**	**1.5% - 30.3%**

(1) 2006 data from EPA (2009) Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006. EPA430-K-04-003

(2) Average coal prices per state over 2010-2011 were taken from US Energy Information Administration, Annual Coal Report, *Table 34. Average price of coal delivered to end use sector by census division and State, 2011, 2010*, found http://www.eia.gov/coal/data.cfm#prices under "Average consumer prices by end use sector, Census division, and state," (accessed on May 31, 2013). Electric power (steam coal): CO $32.0, NM $37.4, PA $54.8, UT $38.1, WV $58.1. Coke (metallurgical coal): $169.0 US-wide

(3) Elk Creek recently implemented a project which captures drainage emissions for electricity generation.

(4) Bailey mine is listed in EPA. 2009. as producing both steam and metallurgical coal but the mine owner; however, CONSOL Energy, describes the mine as producing thermal coal (http://www.consolenergy.com/natural-gas-amp-coal/coal/map-of-mines.aspx)

(5) American Eagle produces both metallurgical and steam coal. Since we do not know the proportion of each type of coal produced at the mine, we made the conservative decision, in the context of this analysis, to use the price for metallurgical coal, which is substantially higher than steam coal.

MTCO2e = million tonnes CO2 equivalent

Appendix D – Comments Previously Submitted to CAR on its Coal Mine Methane Project Protocol Version 2.0

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baseline calculation, and thus not eligible for offset credits.[1] With no existing regulations that force destruction or capture of methane (outside of mine safety rules), the Protocol suggests that the possibility of future regulation is simply one risk factor that projects will have to consider.

This view oversimplifies the applicable Clean Air Act provisions and neglects several key issues, which we discuss below. These issues have potentially significant implications for this Protocol or any other involving a large stationary source of GHGs, both for the Reserve and the California Air Resources Board. As a result, we believe further high-level discussion is required to ensure that the Protocol does not create actual unintended conflicts—or even the appearance of unintended conflicts—with EPA or the Clean Air Act.

Indeed, these sorts of interactions are increasingly likely in a fragmented climate policy landscape, and the Reserve is well positioned to be a leader in developing carefully considered climate strategies that minimize potential conflicts with other regulatory systems.

1.1. Because BACT determinations are made by state permitting agencies, the Protocol could undermine effective implementation of CAA requirements by creating political pressure to weaken BACT standards outside of California.

We are concerned that the Protocol has the potential to undermine or weaken implementation of CAA regulations by creating an incentive for state regulators to weaken BACT determinations for controlling coal mine methane emissions. EPA's recent Tailoring Rule requires certain new facilities or major modifications of existing facilities to obtain a Prevention of Significant Deterioration ("PSD") permit, for which state permitting agencies must determine and apply the best available control technology ("BACT").[2] In particular, major modifications of existing facilities, including coal mines, that result in increased emissions of at least 75,000 tons per year of CO_2e are required to obtain PSD permits.[3]

Although EPA sets the basic contours of the PSD program, application of BACT is left to the states. In *ADEC v. EPA*, the Supreme Court decided that EPA's ability to challenge state BACT determinations is limited to when the state's determination is "not based on a reasoned analysis."[4] This decision gives state permitting agencies wide discretion in determining BACT, subject only to procedural review from EPA.

Because states have effective control over BACT determination, those with coal mine projects seeking offset credits under this Protocol will face additional political

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1 Protocol § 3.4.1.1.

2 *See generally* Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 75 Fed. Reg. 31514 (June 3, 2010).

3 *Id.* at 31516.

4 *Alaska Dep't Envtl. Conservation v. Envtl. Prot. Agency*, 540 U.S. 461, 490 (2004) (citations omitted).

Appendix D – Comments Previously Submitted to CAR on its Coal Mine Methane Project Protocol Version 2.0

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apply, and PSD permits would be required for mines creating new emissions above the established threshold.

The Protocol would benefit from a fuller discussion of how these risks would be distributed, especially with the prospect of lengthy litigation or subsequent regulatory developments. We have several questions about what the timing of these kinds of changes would imply for calculating additionality under the Protocol:

- Does the Protocol's legal requirements test apply at the time the legal requirement is identified (*i.e.*, when a court or administrative agency finds that a PSD permit is required) or when the actual legal requirement is specified (*i.e.*, when a state regulator identifies BACT for a particular mine project)?

- If litigation produces a determination that a major modification took place, does the Protocol's legal requirements test adopt BACT requirements retroactively, from the date of the legal decision, or from the date of the subsequent issuance of a permit? Does it matter whether the question litigated was a new issue that was fairly disputed by both sides?

- If litigation or a new regulation defines a threshold for major modifications, must all applicable projects immediately adopt BACT requirements as part of the legal requirements test, or are those requirements not binding for the purposes of the Protocol during a legally valid gap (*e.g.*, a temporary window for securing permits)?

1.3. Air pollution from coal mines is not yet subject to new source performance standards under Section 111 of the CAA, the future implementation of which would set a floor for state determination of BACT for PSD permits. The Reserve should monitor developments on this front.

EPA has not yet exercised its authority to create performance standards for coal mine methane emissions controls under Section 111 of the CAA, but faces pressure to do so. These performance standards would apply to all new and existing coal mines. In June 2010, a group of environmental organizations petitioned EPA to list coal mines as a category of stationary sources subject to performance standards for GHGs, including coal mine methane as a particular source of concern. EPA has not acted on this petition. As a result, the environmental groups sued, seeking to compel EPA to grant or deny the petition.[6]

The outcome of this ongoing litigation matters, as EPA's performance standard authority extends to both new and existing emissions sources.[7] Moreover, state determinations of BACT cannot allow emissions higher than levels determined under

6 *WildEearth Guardians, et al., v. U.S. Envtl. Prot. Agency and Lisa P. Jackson*, No. 1:11-cv-02064-RJL (D.D.C.) (complaint filed Nov. 17, 2011).

7 42 U.S.C. § 7411(b) (new sources); 42 U.S.C. § 7411(d) (existing sources); *see also* Georgetown Climate Center, Issue Brief: EPA's Forthcoming Performance Standards for Regualting Greenhouse Gas Pollution from Power Plants (Clean Air Act Section 111).

Section 111 of the CAA.[8] That is, state BACT determinations are constrained to be no weaker than a performance standard set by EPA under its § 111 authority. Therefore, we believe the Reserve should pay close attention to this issue going forward, as it may either exacerbate or relieve some of the other CAA interactions described above.

If and when EPA sets a § 111 performance standard, it will act to significantly shift the baseline emissions for all participating or potential projects under the CMM protocol. The concerns raised above in section 1.2 also apply here. Furthermore, the Reserve should plan on this performance standard being subject to lengthy litigation. How will project registrations be treated and offsets generated by registered projects during this period of uncertainty be credited?

2. Additionality. The Protocol's Performance Standard Test does not adequately address the possibility that drainage systems have the economically viable option to inject methane into a commercial pipeline, but choose instead to use or flare methane onsite.

We are concerned that some offset projects may be able to switch back and forth between earning offsets under this Protocol and selling methane into a pipeline network. If permitted, this temporal "stacking" would undermine the additionality of the Protocol, and runs counter to principles articulated in other Reserve protocols.[9]

Our concerns arise because the Protocol's eligibility rules allow a drainage system to qualify for offsets by flaring or otherwise using methane, even if selling methane to a pipeline is commercially viable. In other words, the eligibility rules do not include an analysis of the economic viability of injecting methane into a pipeline network. Drainage projects pass the performance standard test simply if they destroy methane "through any end-use management option other than injection into a natural gas pipeline."[10] Remaining eligibility rules require only that that project start dates be no more than three months after the drainage system begins commencing destruction of methane.[11]

Under these rules, a drainage system that injects methane into a pipeline would not appear to qualify for offsets if the project developer decides to build a flare or other end-use management application to replace pipeline exports. Assuming the switch happens after three months of injection, it would appear to violate the eligibility rule on timing. However, the eligibility rules allow for multiple drainage systems to exist at a single coal mine, raising the prospect that as new boreholes are drilled as the mine face advances, the mine operator could elect to either create offsets by flaring or sell pipeline gas from new drainage wells.

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8 42 U.S.C. § 7479(3).

9 *See, e.g.,* Climate Action Reserve, Rice Cultivation Project Protocol, Version 1.0 § 3.5.3 (prohibiting stacking of ecosystem service payment systems in addition to earning carbon offsets for the same mitigation activities).

10 Protocol § 3.4.2 (based on the analysis in Protocol Appendix A).

11 *Id.* § 3.2.

We would appreciate the Reserve confirming this matter, and suggest further that there is no valid reason to view a project at a mine that has ever injected gas into a pipeline as additional.

Unfortunately, nothing in the protocol rules precludes the reverse ordering: a project that could economically inject methane into a pipeline might choose instead to pursue an on-site activity and earn offset credits. So long as the drainage system does not inject methane into a pipeline network, it is assumed to be additional under the performance standard test.

That assumption is flawed, however, under a variety of plausible economic conditions. Project developers might instead see the Protocol rule structure as giving them the chance to bet long on carbon prices, with a backstop option to sell methane into a pipeline network if carbon prices do not rise as expected. Indeed, the rational project developer considering pipeline sales would be wise to consider whether or not a carbon offset provides a higher value hedge against low gas prices, as Figure 1 demonstrates.

Figure 1: Value of Offset Minus Value of Pipeline Sales (\$ per metric ton CH_4)[12]

		CO2 price ($/tCO2-eq.)				Value of natural gas sales
		5	15	25	50	
Natural gas price ($/mmBTU)	2.5	$ (40.58)	$ 141.92	$ 324.42	$ 780.67	$ 131.83
	3.5	$ (93.31)	$ 89.19	$ 271.69	$ 727.94	$ 184.56
	4.5	$ (146.05)	$ 36.45	$ 218.95	$ 675.20	$ 237.30
	5.5	$ (198.78)	$ (16.28)	$ 166.22	$ 622.47	$ 290.03
	6.5	$ (251.51)	$ (69.01)	$ 113.49	$ 569.74	$ 342.76
	7.5	$ (304.24)	$ (121.74)	$ 60.76	$ 517.01	$ 395.49
Value of carbon offsets		$ 91.25	$ 273.75	$ 456.25	$ 912.50	

Each cell in the main table of Figure 1 shows the difference between the value of the carbon offset derived from flaring methane and the value of selling that methane into a pipeline, for a range of natural gas and carbon prices, per metric ton of CH_4. Positive numbers are highlighted and indicate that for the prices applicable in that cell, the carbon offset is more valuable than the direct sale of methane. Thus, under these conditions, a project developer will prefer to generate offset credits rather than sell captured methane into the pipeline network.

For context, the U.S. Energy Information Administration reports that average wellhead natural gas prices in December 2011 were \$3.06 per mmBTU; prices since 2000

[12] Source: authors' calculations using flaring as an example offset project. Assumptions: 52.73 mmBTU per tCH_4 and 18.25 tCO_2e avoided per tCH_4 destroyed (using GWP and "r" values from Protocol equations 5.5 and 5.9, respectively); prices as shown in chart.

have generally ranged from $2.5 to $7.5 per mmBTU, with a few higher spikes.[13] A carbon price of $5/tCO$_2$e is a reasonable approximation of the voluntary carbon market, whereas estimates of California's compliance costs are bounded by the remaining prices shown here.

We note that at current forward delivery prices for CCAs ($14.80 for Dec 2013 delivery),[14] current compliance grade carbon prices would tend to push a coal mine to orchestrate a switch to selling offsets from selling pipeline gas.

The net effect of these incentives is to undermine a key assumption in the Protocol's additionality calculations. By defining the performance standard test for drainage systems as any control technology that does not involve pipeline injection, the Protocol implies that pipeline sales are already economically viable and that all projects not injecting into pipelines do not find it viable to do so.[15] The calculations presented in Figure 1 contradict this assumption and demonstrate that a rational project developer might prefer to pursue carbon offsets above pipeline sales, with the option to exit the Protocol and sell methane into a pipeline if relative carbon and natural gas prices do not justify the pursuit of offset credits. Indeed, the rational project developer might well prefer to view the Protocol as a hedge against low natural gas prices.

This situation is problematic and undermines the actually additionality of the Protocol. We recommend the Reserve revise the Protocol to prohibit switching from offset credits to pipeline sales, and vice versa.

Our understanding of VAM mitigation technologies is that no rational project developer would seek to invest in the capability to convert ventilation air (less than 1%

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[13] Energy Information Adminstration, U.S. Natural Gas Wellhead Price (March 25, 2012), available at: http://www.eia.gov/dnav/ng/hist/n9190us3M.htm. EIA reports December 2011 prices were $3.14 per thousand cubic feet of natural gas. At 1.025 mmBTU per thousand cubic feet of natural gas, this price is equivalent to $3.06 per mmBTU.

[14] *See* PointCarbon, Carbon Markets North America, 23 March 2012, *at* 2.

[15] Protocol Appendix A draws erroneous conclusions to support the proposition that drainage systems using non-pipeline control technologies are always additional. Specifically, Appendix A concludes that the paucity of non-pipteline control technologies reflects their being uneconomic generally, rather than being less economic than pipeline injection. According to Appendix A, only four of twelve drainage systems that do not have a pipeline interconnection employ an alternative mitigation technology. Of these four projects, two are at mines that also have pipeline injections; the analysis excludes these two projects, and focuses only on the two remaining projects that use methane at mines where no pipeline interconnection is present.

On this basis, Appendix A concludes that "on-site end use projects are uncommon even at mines that do not sell their [methane] to pipelines . . . this finding suggests that such project types are generally uneconomic under current conditions, rather than simply less economic than pipeline sales projects." To the extent two drainage projects permit any valid basis for establishing *ex ante* additionality criteria, a more appropriate conclusion would be that the data cannot rule out the alternative hypothesis that pipeline injection is generally more economic than alternative mitigation measures. The difference matters because the first erroneous conclusion supports the Protocol's additionality criterion (which Figure 1 contradicts), whereas the second conclusion is consistent with both the data in Appendix A and the calculations in Figure 1.

methane) into pipeline quality gas (90-95% methane).[16] This investment would be necessary to create the option for temporal stacking described above. Thus, our concern applies only to drainage systems.

Sincerely yours,

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On behalf of: Dr. Michael Wara
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[16] C. Özgen Karacan et al., *Coal mine methane: A review of capture and utilization practices with benefits to mining safety and to greenhouse gas reduction*, 86 INTERNATIONAL JOUNRAL OF COAL GEOLOGY 121, 147 (2011) (reviewing VAM characteristics and typical pipeline injection standards), *available at:* http://www.epa.gov/cmop/docs/cmm-paper-2011.pdf.