Dominion

Memorandum

May 1, 2006

To:	RGGI Staff Working Group
Via:	Email to RGGICOMM@gw.dec.state.ny.us
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Dominion Preliminary Comments On RGGI Draft Model Rule
As Requested for the May 2, 2006 RGGI Stakeholder Meeting

Question No. 1: ***What are your top 3 to 5 recommendations for the states in finalizing the*** **model rule (other than the offsets component)?**

1. **Price Certainty and Stage One and Two Threshold Prices**: The MOU and Model Rule both need a true price certainty mechanism, such as the CO2 alternative compliance payment (ACP) mechanism of Massachusetts' 310 CMR 7.29. The model rule should contain more specific language on the threshold calculations and the exact sources of price information. Both *allowance* and *offset* prices should be considered in the calculation. The 2% adder in the stage two threshold formula is arbitrary and should be eliminated. 14-months for the market settling period is much too long and should be eliminated. The 12-month period in addition to the '14-month market settling period' appears to mean that this trigger cannot be hit until 26 months have transpired. Twenty-six months is too late to mitigate CO2 cost adder impacts on fuel diversity and consumer prices. The threshold prices should simply be based on a 12-month rolling weighted average. Transactions (a) between affiliates, subsidiaries, or otherwise related companies or (b) that are part of fossil fuel and/or electricity contracts, should be excluded from the methodology, as they may not necessarily represent market prices. If an offset trigger event eliminates the 2:1 geographic discount and expands the geographic area of eligible offsets – there should be no reset in the following compliance period. Otherwise, the financing of such projects may be impossible due to the potential for reset, especially if the compliance period is not extended, and the corresponding offset value discount.

2. **Allowance Allocations and Early Reduction Allowances**

   (1) **Consumer Benefit Allocations (CBA) and Auctions** – Specific language is required with regards to how the states will "release" the consumer benefit allocations to the emission trading market. The language should clarify how long the state is allowed to hold onto the allowances, and what specific distribution mechanisms will be considered. Since many budget sources will have a dearth of allowances to match their actual operating emissions (given the likely distribution

methodologies to be employed by each state and the percentage limits on offset use), these sources should have the "right of first refusal" for acquiring the CBA allowances. Specific language is needed so that speculators and other third parties are not allowed to participate in the CBA market until the needs of the operating unit owners are satisfied.

If allocated directly to distribution companies or industrial sources for auctioning/selling, those entities should be required to utilize the proceeds in specific areas to meet the goals of the CBA, and be required to execute an agreement for sale of the allowances within 30 days of their allocation.

(2) **ERA's** - Total Facility shutdowns should be eligible for early reduction allowances (ERA's). We understand the regulators do not want to provide a public policy incentive for facilities to shut down. However, RGGI is a policy that is aimed at turning over the electric sector's existing fossil fleet in order to achieve greenhouse gas reductions. Crediting unit shutdowns would help the market more quickly turn over that fleet in the most efficient manner possible. To address the public policy concern of shut downs, Independent System Operators (ISO's) should judge which units will not be allowed to shut down for reliability purposes and keep those units operating through appropriate market rules or mechanisms.

Unit shutdowns are only given credit under the ERA provisions, which limits their value to the period prior to January 1, 2009. Units shutdown should get credit for a **longer period of time**, such as ten years, for their CO2 emission reductions, since those reductions are permanent. Also, those units shutdown after January 1, 2009 warrant a mechanism for credit, as well.

(3) In order to qualify for ERA's, a facility has to improve its CO2 *emission rate* as well as its *total tons*. Since this is a cap and trade program based on absolute tons, there is no justification for the use of an *emission rate*. The driver for facility total reductions (market forces, voluntary unit curtailments etc.) is irrelevant from the environment's perspective. Therefore, any reductions in total (absolute) tons prior to January 1, 2009 should count as an ERA.

3. Definitional Changes Are Needed

(1) **Excess Emissions:** This definition is ambiguous and assumes that each unit under the program will be assigned a "CO2 budget" for their CO2 emissions. The way this program is designed to work is that units will be allocated allowances and will be able to use offsets for a certain percentage of their total emissions. The combination of allowances and offsets will be used to cover their compliance obligations and be available as compliance deductions from a source's compliance account at the end of a control period. As an alternative to the existing definition, "excess emissions" (EM) should be defined as the difference between the total emissions (TE) and the sum of allowances (A) and offset (O)

deductions used to cover those total emissions less any CO2 emissions attributable to burning biomass (B). In other words:

$$\mathbf{EM = [TE - (A+O)] - B]}$$

To remain in compliance, a unit must have EM in the formula above equal zero or less. Any emissions greater than zero, would be considered to be 'excess emissions' which are subject to the provisions of XX-1.5(d) Excess Emission Requirements.

(2) **Biomass:** Definition of eligible biomass is much too stringent and serves to preclude some sources of biomass (like manufactured fuel cubes or natural oil by-products) that could be co-fired in existing units and also help to ease landfill use. In the context of a GHG reduction policy the stringency of this definition runs counter to the program goals and precludes the environmental co-benefit of reducing materials that would otherwise end up in a landfill.

4. **Applicability:** The limited exemption of XX-1.4(b) for units with electrical output to the electrical grid restricted by permit conditions should be a *mandatory* exemption, not an *optional* exemption under applicability.

5. **Duplicity Clarification for The Electric Sector:** Section XX-1.5 (g)(1) of the Standard Requirements allows for RGGI to be in addition to other state CO2 regulations. However, in doing so, it allows for RGGI to be *duplicative of existing* state CO2 reduction programs, which are already in effect for certain existing fossil fuel facilities from the electric sector. We suggest that clarification language be added to ensure a facility only has to comply with one set of requirements and not multiple CO2 reduction programs at the state and regional level. In particular, since Massachusetts already has 310 CMR 7.29, should Massachusetts ever decide to join RGGI, those facilities subject to 310 CMR 7.29 should continue to be subject to the requirements of 310 CMR 7.29, while remaining exempt from the RGGI cap requirements. Other EGU's in Massachusetts, not subject to 310 CMR 7.29, would be subject to RGGI requirements.

Question No. 2: What are your top 3 to 5 recommendations for the states in finalizing the offsets component?

1. **General Provisions Need to Be Less Stringent or Clarified**

(1) Offset projects should count regardless of the underlying financial motives for going forward with a project. Therefore, additionality of all offset projects should only be judged based on "regulatory surplus."

(2) It seems unlikely that any projects will get financed with the regulatory change provisions (uncertainty) proposed. Offset project should continue to be awarded offset allowances from a project activity that has already been certified by the RGGI process, even if the project activity becomes required by law during the

lifetime of the project. We also suggest discussion with the financial community about this aspect and suspect that offset project financing will be difficult if not impossible if this provision is not changed.

(3) Projects that are funded *above and beyond* system benefit charge funding or consumer benefit or strategic energy funding should be eligible for the incremental piece of offsets generated from those funds. Most projects will benefit form having multiple funding sources by looking more attractive to the financial investment community.

(4) RECs and CO2 offsets should be allowed to be treated as separate, but simultaneously generated commodities.

(5) Projects under other voluntary greenhouse gas programs should count if otherwise eligible.

(6) A ten year crediting allocation period with an extension for one ten year period may be too short to justify project financing.

(7) In order to have an adequate number of offsets in the market, the Staff Working Group will need to reconsider the timing of offset projects which is limited to only those that have initially commenced on or after December 20, 2005. At a minimum, offsets generated after December 20, 2005 from ligitimate projects regardless of when the project initially commenced should be allowed to count.

(8) The provisions of "ineligibility due to noncompliance" in which the "regulatory agency may revoke any and **all offset allowances in a project sponsor's account**" is unnecessarily stringent and adds to the financing uncertainty of offset projects. Only those offsets that are proportional to a 'proven' noncompliance should be deducted from a project sponsor's account. There should be an appeal provision for the noncompliance deduction, as well.

(9) There is a lack of an appeal process for the project "consistency determination."

2. **Project Specific Requirements Need To Be Less Stringent**

(1) **Afforestation** - The 20% discount to address uncertainty of "permanence" will prevent many projects from being funded that would otherwise happen if this discount were not present. There are other mechanisms to address this issue, including insurance policies, which could provide for substitution of "offset credits" from other projects instead of monetary payments. Also, the legally binding **permanent conservation easement** is overly stringent, considering the offset credits will only be issued for a small time period (10-20 years). The conservation easement should be limited only to the period of offset credit generation.

(2) **Reduction or avoidance of CO2 emissions from natural gas, oil or propane end-use combustion due to end-use energy efficiency.** – The applicability of

this should not be limited to residential and commercial buildings and should include **industrial** buildings. Limiting the market penetration rate of eligible projects to only 5% should be eliminated altogether. Otherwise only projects which involve cutting edge technology, will be eligible.

(3) **Natural Gas T&D –** The staff working group should consider working with INGAA to develop Section XX-10.5(f) regarding reductions in emissions from natural gas transmission and distribution equipment.