

An Assessment of the Public Benefit Set Aside Concept Taking Into Account the Functioning of the Northeast/Mid-Atlantic Electricity Markets

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I. Introduction & Summary

The Regional Greenhouse Gas Initiative (“RGGI”) has been instituted to address the issues associated with the proposed reduction of carbon dioxide (CO₂) emission levels. One of the key issues under review is the amount of CO₂ allowances that will be allocated to existing generating facilities. Taking the position that full grandfathered allocations would allow existing generators to reap a windfall, Resources for the Future (“RFF”) has proposed to allot each generating facility only a 20% CO₂ allowance allocation based on its historic emission levels. Under this proposal, known as the public benefit set aside concept, existing generating facilities then would be required to purchase their remaining mandated allowances through auction or some other mechanism (“RFF Proposal”). However, as demonstrated more fully herein, the RFF Proposal is fatally flawed in a number of material respects, and therefore, it must be rejected.

Specifically, the RFF Proposal, and the underlying analyses used to support it, fail to consider many operating limitations faced by generators that supply energy in the wholesale day-ahead and real-time electric markets. By failing to consider these factors, the RFF Proposal markedly understates the financial impact of its proposed allocation methodology on these facilities – an impact that is so severe that it is likely to cause some of these units to shut down. Nor does the RFF Proposal take into account the fact that there are a significant number of existing generating facilities that are parties to long-term contracts. Because these facilities have no way to recoup the additional costs that the RFF Proposal would impose on them, they, too, may face shut down decisions.

As a direct result of these shutdowns, most, if not all of the consumer benefits that RFF alleges will result from requiring existing generating resources to purchase allowances will be lost. In addition, the fuel diversity benefits that currently result from having a generation fleet that operates on different fuels will be squandered. Thus, the RFF Proposal also will adversely affect system reliability.

II. Background

The proposal to require existing generating facilities to procure most of their CO₂ allowances via auction has been proposed by Resources For the Future.

RFF has asserted that it supports the auction approach because it believes that allocating the allowances directly to generation sources would result in a windfall to generators. RFF further believes that increased electricity prices will allow generating units largely to recoup the costs that they will incur to procure the required allowances.

RFF has performed numerous studies of the allowance allocation issue in the last several years. However, most of the RFF studies either analyze the impact on producers in aggregate, as if all the generation were owned by one entity, or analyze the impact on generic generation portfolios. For the reasons set forth below, these approaches grossly misinterpret the impact that the RFF Proposal will have on individual generation owners.

III. The Haiku Model

RFF has used the Haiku Model as the basis of the studies that it has conducted of the electricity market.¹ The Haiku Model is a high level scenario model of the contiguous US electric system. There are several simplifying assumptions incorporated into the Haiku Model that substantially limit the degree to which this model accounts for actual operating circumstances and conditions. First, the Haiku Model relies upon a depiction of the transmission systems in these regions that is too simplified. It represents the entire contiguous US electric system as thirteen NERC regions and subregions -- New England, New York, MAAC, ECAR, STV, FRCC, MAIN, MAPP, SPP, ERCOT, CNV, NWP and RA – as they were defined in 1999. Generation is modeled within each region with the assumption that it meets its region's loads. Additionally, the model represents the ability to trade energy between regions (i.e. to use generation from one region to serve part of the energy requirements in another region) by focusing solely upon the transfer capabilities that exist between the regions. However, the model does not appear to include any representation of the transmission system within a region, and therefore, it fails to account for internal transmission constraints that limit the ability of generators to meet load.

Second, the Haiku Model fails to adequately represent load conditions. It represents the annual electricity demand for each region using three seasons: Winter (December, January and February); Spring/Fall (March, April, October, November); and Summer (May through September). The summer season is designed to coincide with the Ozone season in the Northeast. The seasons then are divided broadly into four time blocks: baseload (70% of hours with the lowest loads); shoulder (next 25% of hours); peak (next 4 % of hours); and superpeak (highest 1% of hours). From the model description, it appears that the Haiku Model structure only allows for a single average load for each of these time periods in each season. Thus, by design, the Haiku Model does not appear to account for daily or weekly load fluctuations and the impact on unit operation caused by these fluctuations. Nor does it represent any relationship between the different periods within a season.

Third, the Haiku Model represents generation resources in a similarly simplified manner. Generation availability is modeled using the net capability of each unit after deducting an allowance for forced and maintenance outages. Similar types of units are then combined into aggregate Model Plants. There are a total of 46 Model Plants used in the Haiku Model. Not all

¹ Information on the Haiku model presented in this memo is taken from "The RFF Haiku Electricity Market Model", by Anthony Paul and Dallas Burtraw, June 2002.

Model Plants are used in all regions; existing plant types are represented by only 31 of the 46 Model Plants.

IV. The Haiku Model Fails to Take Into Account Factors Faced By Generators Participating In The Wholesale Market That Make The RFF Proposal Infeasible

Due to the drastically over-simplified representation of the US electric system upon which the Haiku Model is based, the Haiku Model, by design, wholly fails to take into account -- much less address -- the actual system conditions faced by generating units that operate in the day-ahead and real-time wholesale energy markets. In so doing, the Haiku Model grossly underestimates the adverse impacts that the RFF proposed allocation methodology will have on generating units. When these factors are taken into consideration, it is clear -- contrary to RFF's misguided assertions -- that the market clearing prices will not be sufficient to allow generating facilities to recoup the costs that they will incur to purchase CO2 allowances in the market. Over time, the inability to recover these costs is likely to force some units to cease operations.

A. Generation Unit Characteristics

The Haiku Model ignores many physical limits that are faced by generating units, such as minimum generation levels, minimum run times and minimum down times. Each of these factors directly affects the degree to which a wholesale generator will be able to recoup its CO2 allowance costs through the market clearing price. For example, when units are operating, they generally must maintain minimum generation levels. However, energy clearing prices are based on the costs associated with incremental heat rates, not minimum generation levels. Incremental heat rates, and therefore CO2 emission rates, are lower for the incremental generation above a unit's minimum generation level than for its minimum generation level. Therefore, even if a unit is able to set the clearing price in the market and has incorporated its allowance cost into its bid, that clearing price will not be sufficient to allow the unit to recover the total allowance cost that it has incurred.

Likewise, the Haiku Model's failure to represent either unit minimum run times or minimum down times also results in a flawed analysis. Most electricity is provided by units that have relatively long minimum down times and minimum run times. These units cannot shut down during low load periods and still be available to provide energy during higher load periods. As a result, these units must continue to run through the low load periods (i.e., through the night and over many weekends) so that they are available to meet the electric system's energy and operating reserve requirements of the higher load periods. During these low load periods, the units have higher emission rates but receive very low clearing prices. For example, the energy clearing price for such a unit in western New York during low load periods is likely to be set by a combined cycle unit's marginal heat rate. That clearing price will not allow this unit to recover the CO2 allowance cost that it has incurred to operate during that time.

B. Intra-Regional Transmission System Constraints

The Haiku Model's failure to account for any intra-regional transmission constraints produces a grossly inaccurate representation of the Northeast. Transmission interfaces within New York and New England have persistent congestion that plays a significant factor in electric system planning and generating unit' economics. These transmission limits affect both the energy and capacity markets in the region.

Specifically, since the inception of its competitive wholesale electricity markets, New York has had three separate capacity sub-regions that reflect transmission limitations within the State. ISO-NE is in the process of implementing separate capacity sub-regions to reflect the transmission limitations within the New England region. The capacity payments that generators receive in New York – and, beginning January 1, 2006, in New England -- vary significantly depending upon the capacity sub-region in which the generator is located.

On the energy side, the Haiku Model assumes that generators in western New York can serve load anywhere in New York State. However, there are frequently transmission constraints that break the ISO into separate energy markets. These constraints directly limit the ability of western New York resources to be chosen to provide energy to the Lower Hudson Valley, New York City and Long Island areas. When these constraints are binding, western New York energy prices are based upon western resources, not the higher priced resources in the southeastern part of the State – these western energy prices are significantly less than what have been projected by the Haiku Model.

C. Wind Generation Considerations

On September 22, 2004, the New York Public Service Commission issued an order in Case 03-E-0188 implementing a renewable portfolio standards program in New York that is designed to allow New York State to achieve a 25% renewable energy portfolio by 2013. The Haiku Model is not equipped to address the potential impacts of the newly implemented RPS Program.

Specifically, the RPS Program may result in significant amounts of wind generation being constructed in the western part of New York State. Because wind-powered generating facilities have very low variable costs and will receive a renewable premium payment, it is likely that these units will set depressed energy clearing prices during the low load periods. However, it also is likely that many of the fossil-fueled western resources will be required to stay online -- at lower generation levels -- so that they can remain available to meet load pickup, provide system control, and provide protection against the system impacts that will result from wind variability. Thus, higher emitting facilities will incur significant CO2 costs in the name of assuring system reliability, yet the energy clearing price, once again, will be insufficient to allow these resources to recover their CO2 allowance costs.

V. The RFF Proposal Fails To Account For The Impact On Generating Facilities That Are Parties To Long-Term Contracts

The predicate underlying the RFF Proposal is that market clearing prices will provide generators with the needed revenue to procure the vast majority of their CO2 allowances by auction or in the market. However, the RFF Proposal ignores the fact that numerous market

participants sell their energy under physical or financial bilateral contracts. In some instances, these contracts were executed to support financing decisions. Others were executed to provide price certainty to both buyers and sellers. In addition, there are a significant number of “legacy” contracts in the markets for generating resources, such as PURPA units. The generating units that are parties to these contracts do not receive the market clearing prices. Thus, if the RFF Proposal is adopted, these units will face additional costs but will have no mechanism to recoup any of them. Absent allotting generating facilities that are parties to long-term contracts a full allocation of their respective CO2 allowances, each of these facilities will suffer severe economic harm that may force some of these units to cease operations because they have been made uneconomic by this program.

VI. Requiring Generating Facilities To Procure CO2 Allowances Via An Auction Or In The Market Will Not Result In Net Economic Benefits

As noted above, the analyses underlying the RFF Proposal focus on the aggregate impacts on the generation sector as if generation owners each owned a slice of the system. In so doing, they largely ignore generation ownership circumstances that render the RFF Proposal infeasible. Most of the generation assets that were sold during deregulation were financed in individual packages. By requiring generating facilities to incur CO2 allowance costs that they cannot recoup, the RFF Proposal will make individual packages uneconomic. This will result in a series of individual financing failures, which, in turn, will lead to increased future capital costs, eroded bond ratings and increased risk profiles. These factors all will lead to increased costs that ultimately will be borne by consumers in energy markets.²

Moreover, the RFF Proposal is likely to lead to cost increases in both the energy and capacity markets that are in place in the proposed RGGI regions. Because higher emitting facilities will not be able to recover the costs that they will incur to purchase mandated CO2 allowances, a number of these units are likely to be forced to shut down. Likewise, CO2 emitting units operating under long-term contracts also will be unable to recoup these costs and may be forced to shut down. The shutdown of these resources will lead to tighter supply conditions which, in turn, will cause the installed capacity market to clear at higher prices. In addition, with the shutdown of units that previously had been lower cost facilities in the market, the market will clear higher on the energy supply curve during most load conditions. This will lead to higher energy prices. These increased energy and capacity costs will offset most – if not all – of the economic benefit that RFF has alleged will be gained by requiring generators to purchase the vast majority of their CO2 allowances.

VII. The RFF Proposal Will Adversely Impact System Reliability

If adopted, the RFF Proposal also will adversely affect system reliability. Currently, the overall generation portfolio in New England is comprised predominantly of generating facilities that operate on natural gas. In contrast, New York, to date, has maintained a portfolio with a more

² The fact that these financial impacts will be the direct result of a regional regulatory decision will exacerbate concerns of the financial risk associated with investment in the electric system at the very time when the industry and regulators are attempting to quell the concerns brought on by the collapse of Enron.

diversified fuel mix. New England was forced to shed electric load last winter due to natural gas shortages and its over-reliance on natural gas fired facilities. During those periods, New York was able to take advantage of its diversified portfolio to meet its load and to provide energy to New England. Absent New York's fuel diversity, the rolling blackouts in New England would have been even more severe and, indeed, New York, too, may have been forced to shed load. As a result of last winter's experience, both ISO-NE and the NYISO have begun to focus on fuel diversity as a critical component of ensuring system reliability.

The under-allocation of CO2 allowances to generating facilities that will result under the RFF Proposal will have the most significant financial impact on higher emitting generation resources – the very resources that provide this critically needed fuel diversity. As a result, some of these units are likely to shut down. This, in turn, will artificially lead to further reliance on natural gas as the predominant fuel for electric generation. Fuel diversity – and, directly with it, system reliability – will be lost.

VIII. Conclusion

RFF attempts to justify its proposed limited generator CO2 allowance allocation by asserting that generating facilities will be able to fully recover the newly imposed allowance costs from energy clearing prices. However, the RFF Proposal fails to adequately consider the operating requirements faced by generators in wholesale electric markets. RFF also fails to address the effect of its proposal on generating facilities that are parties to long-term contracts. Consideration of these factors reveals that the RFF Proposal may very well lead to unit shutdowns, and concomitantly, higher energy and capacity prices matched with less fuel diversity. Because the RFF Proposal ultimately will not result in net economic benefits and may adversely affect system reliability, it is not a feasible alternative to allotting full grandfathered allowance allocations to existing generating facilities. Thus, it must not be adopted.