STATE OF VERMONT

PUBLIC SERVICE BOARD

Docket No. 7533

Investigation into Implementation of Standard )
Offer Prices for Sustainably Priced Energy )
Enterprise Development ("SPEED") resources )

# DIRECT TESTIMONY OF
# JOHN DALTON
# ON BEHALF OF THE VERMONT PUBLIC SERVICE BOARD

OCTOBER 30, 2009

Summary: The purpose of Mr. Dalton's direct testimony is to provide a foundation for the financial model and the renewable generation technology cost, performance, tax and financing assumptions that will be used by the Board to make its price determinations for this Docket. Mr. Dalton will likely submit additional testimony during the rebuttal phase of this proceeding regarding his recommendations for the model or models to be used as well as the input assumptions for the various renewable energy technologies.

## I. INTRODUCTION

**Q. Please state your name, business address, and the nature of your business.**

A. My name is John Dalton. I am President of Power Advisory LLC (Power Advisory). My business address is 706 West Street, Carlisle, Massachusetts. Power Advisory is a management consulting firm focusing on the electricity sector and specializing in electricity market analysis and strategy, power procurement, energy policy development, and electricity project feasibility assessment.

Power Advisory's clients include power planning and procurement agencies, regulatory agencies, generation project developers, and electric utilities.

**Q. On whose behalf are you testifying in this proceeding?**

A. I am appearing on behalf of the Vermont Public Service Board (Board or PSB).

**Q. What is the purpose of your testimony?**

A. I have been asked by the Board staff to provide a foundation for the financial model and the renewable generation technology cost, performance, tax and financing assumptions that will be used by the Board to make its price determinations for this Docket.

In this direct testimony I focus on reviewing the structure of the financial pro forma model that was used by the Board in Docket 7523 to evaluate the reasonableness of the legislatively proposed Standard Offer prices and proposing changes to this model. Rather than test this model through a formal adjudicatory process, a more collaborative

approach is being used in an effort to reach agreement with the parties in this proceeding on the basic model structure.

I anticipate submitting additional testimony during the rebuttal phase of this proceeding regarding my recommendations for the model or models to be used as well as the input assumptions (e.g., renewable generation technology cost, performance, tax and financing assumptions). This assessment of inputs will be based in part on the direct testimony provided by other parties and their information request responses. I will use this direct testimony and these information request responses to inform my opinion of the reasonableness of these assumptions.

In addition, I will be responsible for running the model that is ultimately used by the Board to make its final price determinations and specifying in the model the "best estimates" based on the record in this docket as weighed by the Board. Finally, Board staff have indicated that they may request that I offer recommendations on adjustments to the standard offer prices produced by the model. These adjustments would seek to ensure that the resulting prices provide "sufficient incentive for the rapid development and commissioning of plants", while not exceeding "the amount needed to provide such an incentive." (Sec. 4. 30 V.S.A.§8005 (b)(2)(B)(i)(III))

## II. PROFESSIONAL BACKGROUND

**Q. What is your professional and academic background?**

A. I am an electricity market and policy expert with over 20 years of experience in the electricity sector. I specialize in energy market analysis, electricity policy analysis

and development, power procurement and contracting, generation project evaluation, and strategy development. I am experienced in the evaluation and analysis of electricity markets and the competitive position of generation technologies and projects within these markets.

I have developed and overseen the development of numerous market price forecasts across North America, including forecasts for the Independent System Operator of New England (ISO-NE) market in which the Vermont distribution utilities participate. These price forecasts were used to support generation project development efforts, project financings, regulatory policies, and power procurement efforts.

I have reviewed numerous electric utility avoided cost estimates and advised clients on the reasonableness of these estimates and the methodologies for developing them.

I have developed detailed financial pro formas of numerous generation projects employing a wide range of technologies to assess the projects' financial feasibility and economic value. These analyses often identified strategies for enhancing project values.

I have assisted clients in drafting long-term power purchase agreements with appropriate allocations of project risks and contract terms to enable project financing and development, while maintaining appropriate incentives for efficient project operation. I have led the negotiations of power purchase agreements. I have extensive experience with the development of competitive bidding processes for conventional fossil, cogeneration, and renewable generation technologies and the development of successful proposals in response to such processes.

I have served as a consultant to the electricity sector for over 20 years with various firms and prior to this served as an economist with the Massachusetts Energy Facilities Siting Council where I reviewed electric utility demand forecasts and supply plans and applications for the construction of new energy facilities. Prior to this, I served as an economist with the Massachusetts Department of Environmental Protection where I assisted with the costing of emission control initiatives that were targeted at electric utilities and major industrial facilities.

I have testified in a number of proceedings across North America on issues ranging from the need for new electric generating facilities, standard offer programs for the procurement of renewable energy and capacity, electric utilities' competitive procurement programs, wholesale electricity market prices, transmission pricing policy, and the likely competitiveness of wholesale power markets.

I have a BA in Economics from Brown University and an MBA from Boston University and have taken courses in resource planning methods and regional planning at the Massachusetts Institute of Technology and Boston University. A copy of my curriculum vitae is attached as Exhibit No. ___ (JCD-1).

**Q. Do you have experience with standard offer programs?**

A. Yes. I have extensive experience with standard offer programs. I advised the Board with the development of this standard offer program and the review in Docket 7523 of the legislatively proposed standard offer prices. In this docket, I offered an

independent opinion on the appropriate cost, performance and financing assumptions for the different eligible renewable generation technologies.

Prior to this I advised the Ontario Power Authority (OPA) with the development of their initial estimates of the prices that they proposed for their feed-in tariff program. As part of this effort, I developed the initial financial pro forma models that estimated these feed-in tariff rates.

In addition, I have provided presentations at conferences and workshops on the issues associated with the design of standard offers. In 2005, I led a team that assisted the OPA with the design of its Standard Offer Program.

In October 2007, the OPA engaged Power Advisory to review its Standard Offer Program for photovoltaics and recommend modifications to the program. In June 2008, Power Advisory was engaged to assist the OPA with refining the Standard Offer Program given the significant market uptake and identified program deficiencies.

In these various assignments, I have reviewed how standard offer programs and feed-in tariffs have been implemented in other markets; contrasted feed-in tariff rates in these markets; evaluated the range of possible contract prerequisites and milestones; reviewed security requirements; evaluated appropriate standard offer pricing levels; and performed financial analyses to estimate the appropriate feed-in tariff rates for a wide range of renewable energy technologies.

## III. OVERVIEW OF DIRECT TESTIMONY

**Q. What is the focus of your direct testimony in this proceeding?**

A. My testimony reviews the financial pro forma model that was developed for the Cost Analysis Subgroup that was established in Docket 7523 and used by the Board in this docket to evaluate the reasonableness of the standard offer prices specified in the Vermont Energy Act of 2009 (Act). This direct testimony also identifies the refinements to the model that I am proposing to make. As part of the process of reviewing this model, I requested comments from all the registered parties in Docket 7533 on "structural" changes that they would propose to make to the model. In addition, I conducted targeted outreach to solicit comments from parties that were involved in the initial development of the model or offered comments on earlier versions of the model. A workshop has been scheduled for November 5, 2009 to discuss the changes proposed.

## IV. REVIEW OF THE FINANCIAL MODEL

**Q. Could you review the financial model that was used in Docket 7523 to evaluate the reasonableness of the legislatively proposed prices?**

A. Certainly. The financial model projects the after tax cash flows that would be available to the project developer and is commonly referred to as a cash flow model. The basic structure of the model is to determine a revenue stream over a given contract period (typically 20 years) that allows the developer to recover the costs of developing, building and operating a renewable energy generation project and earn the target return on equity invested. The model

calculates the price in dollars per megawatt hour that will yield the annual cash flow stream necessary to achieve the target return on equity.

To compute the net annual cash flow, annual cash expenditures based on technology specific cost and performance assumptions are subtracted from the cash inflows. These annual cash expenditures include insurance, operations and maintenance expenses, interest and principal payments and income and property taxes. Cash inflows are typically limited to revenues from the sale of electricity under the Standard Offer Contract, but for farm methane projects include other revenues.

The first step in this process is to calculate the EBITDA (earnings before interest, taxes, depreciation, and amortization) by subtracting operating expenses (insurance, operations and maintenance expenses and property taxes) from project revenues. Interest expense and tax depreciation are subtracted from the EBITDA estimate to yield pre-tax income. State and federal income taxes are deducted from pre-tax income to provide net income. After tax cash flow is this net income with debt principal payments and any annual capital expenditures deducted and with tax depreciation, any project residual value at the end of the contract term, federal and state income tax credits (ITCs) added back. The formula used in the cash flow model differs slightly (i.e., it doesn't calculate net income and derives the after tax cash flows directly from the EBITDA) from this approach, but provides the same result.

The annual after tax cash flows are used to calculate an internal rate of return (IRR) earned by the equity investor on the generation project. The model is solved by establishing the price (i.e., the presumed Standard Offer Contract price) that produces the target IRR for the present value of after tax cash flows.

**Q. Why is a cash flow model appropriate to establish the prices for Vermont's Standard Offer Program?**

A. Cash flow models are typically used by generation project developers and lenders to evaluate the economics of generation investment alternatives. Therefore, they provide a reasonable basis for assessing the price that is required to provide lenders with sufficient debt service coverage ratios and investors with the after tax cash flows that they require to earn their target return.

Furthermore, the Board's September 15, 2009 decision in Docket 7523 noted: "[t]here was little disagreement over the modeling tool being used. The major issues associated with the modeling centered on the input assumptions and drivers. Residual concerns with the model largely centered on its ease of use, complexity, and presentation."(p. 23).

**Q. Have you benchmarked the cash flow model to other models to evaluate the reasonableness of the results it provides?**

A. Yes. I compared the results of the cash flow model with those provided by the levelized carrying charge model that I initially developed as an alternative model for the Board in Docket 7523. However, this levelized carrying charge model is a "coarser" model which does not adequately consider the accelerated depreciation benefits offered by renewable energy generation technologies. As such, it is likely to overstate the effective costs of these technologies. When adjusted for this deficiency the results of this levelized carrying charge model were within 10% of the cash flow model results. This difference in no way suggests that the cash flow model provides unreasonable results. However, it does suggest that the simpler levelized carrying charge model provides a less refined, and higher estimate of the appropriate standard offer prices.

**Q. What changes are you proposing to make to the financial model?**

A. I am proposing to make a number of changes. First of all, for the modeling that was performed in Docket 7523 the Vermont Department of Taxes offered recommendations regarding different tax-related assumptions for the financial modeling. In particular, an approach for establishing property taxes was outlined by the Department of Taxes which differed from that used in the initial modeling that I performed on behalf of the Cost Analysis Subgroup or was employed by the Department of Public Service (DPS) in its subsequent model runs.

Second, the model doesn't recognize that for some technologies there is likely to be a degradation in output over time. This output degradation is most important for solar PV technologies. Therefore, for solar PV projects I expect to propose an output degradation factor that would be used to reduce the project output over time.

In addition, as discussed, I provided an opportunity for all the parties in Docket 7533 to identify "structural" changes to the model that they believe should be made to ensure that it better reflects the true cost of developing, building, financing and operating the relevant renewable energy generation technologies. I received a series of comments and recommended changes from the parties.

**Q. What were these comments on the model?**

I received three comments on the model. The DPS commented that for farm methane projects the assumption that project developers (assumed to be the farm owner) would not be able to utilize the ITC was inconsistent with the assumption in the cash flow analysis that that the developer paid taxes. Project developers were assumed to have

insufficient income to utilize the ITC so no ITC was considered in the cash flow analysis. Therefore, the DPS suggested that income taxes shouldn't be considered for these projects.

The DPS also proposed using a two-tier pricing structure for farm methane projects, with the first tier providing prices that are needed to provide sufficient debt service coverage ratios for the duration of the debt term and the prices during the second tier covering expenses and contributing to the required return on equity. This pricing structure is more likely to be appropriate for farm methane projects given that their assumed debt terms (or tenors) are considerably shorter (e.g., 7 to 10 years) than their contract terms (e.g., 20 years).

An additional comment was offered by ReKnew Energy Systems, Inc. suggesting that additional consideration should be given to the costs of interconnection studies and resulting system upgrade costs that would be assigned to the project. I view this as a comment regarding the reasonableness of assumptions rather than the model structure itself. Therefore, I will address it in my rebuttal testimony when I more completely assess the reasonableness of the appropriate technology assumptions.

## V. REVIEW OF ASSUMPTIONS

**Q. Could you review the general assumptions that were used to support your recommendations regarding the initial price determinations.**

A. Certainly. The basic assumptions for each of the technologies for which Power Advisory developed Standard Offer price estimates are identified in Table 1. Most of

these assumptions were proposed by other parties in the proceeding. However, I did develop an independent estimate of the capital costs of solar PV projects and the debt term and cost of debt for farm methane projects.

I am planning to reevaluate these assumptions as appropriate based on the evidence presented in this docket and to present these assumptions in my rebuttal testimony.

**Table 1: Generation Technology Assumptions**

| **Technology** | **Wind** | | **Farm Methane** | | |
|---|---|---|---|---|---|
| **Project** | **1.5 MW** | **100 kW** | **Large Farm (300 kW)** | **Medium Farm (65 kW)** | **Medium Farm (35 kW)** |
| Net Capacity (kW) | 1,500 | 100 | 300 | 65 | 35 |
| Installed Capital Cost ($/kW) | $3,000 | $6,750 | $7,628 | $12,308 | $15,714 |
| Fixed O&M ($/kW-year) | $72 | $142 | $767 | $1,801 | $2,936 |
| Federal Income Tax Rate | 35% | 35% | 20% | 15% | 15% |
| Vermont Income Tax Rate | 8.5% | 8.5% | 5% | 5% | 5% |
| ITC (%) | 33.6% | 33.6% | 0.0% | 0.0% | 0.0% |
| Grant ($/kW) before tax | NA | $250,000 | $1,928 | $7,654 | $10,696 |
| Net Capacity Factor | 26.6% | 23.8% | 76.5% | 76.5% | 76.5% |
| Cost of Debt | 7.5% | 7.5% | 5.5% | 5.5% | 5.5% |
| Debt/Equity Ratio | 60/40 | 60/40 | 75/25 | 75/25 | 75/25 |
| Debt Term | 18 | 18 | 10 | 10 | 10 |
| Contract Term | 20 | 20 | 20 | 20 | 20 |
| Asset Life | 20 | 20 | 20 | 20 | 20 |

| Technology | Photovoltaics | | | | Hydro |
|---|---|---|---|---|---|
| **Project** | **<15 kW** | **15-150 kW** | **150-500 kW** | **500-2.2 MW** | **Composite Project** |
| Net Capacity (kW) | 15 | 150 | 150 | 2200 | 1,278 |
| Installed Capital Cost ($/kW) | $7,010 | $6,070 | $5,700 | $5,415 | $4,173 |
| Fixed O&M ($/kW-year) | $104 | $91 | $86 | $82 | $162 |
| Federal Income Tax Rate | 35% | 35% | 35% | 35% | 35% |
| Vermont Income Tax Rate | 8.5% | 8.5% | 8.5% | 8.5% | 8.5% |
| ITC (%) | 60.0% | 60.0% | 60.0% | 60.0% | 33.6% |
| Grant ($/kW) before tax | NA | NA | NA | NA | NA |
| Net Capacity Factor | 13.0% | 13.0% | 13.0% | 14.0% | 44.9% |
| Cost of Debt | 7.5% | 7.5% | 7.5% | 7.5% | 7.5% |
| Debt/Equity Ratio | 50/50 | 50/50 | 50/50 | 45/55 | 65/35 |
| Debt Term | 18 | 18 | 18 | 18 | 18 |
| Contract Term | 25 | 25 | 25 | 25 | 20 |
| Asset Life | 25 | 25 | 25 | 25 | 30 |

Note: Photovoltaic installed capital costs are $/kW dc)

**Q. Could you please review the basis for these solar PV capital cost estimates?**

Certainly. Power Advisory's PV capital cost estimates were based on the Massachusetts Technology Collaborative (MTC) PV project installation database. An analysis of the installation costs of these PV projects indicated that costs were declining over time, consistent with the experience in the industry. To capture the most recent project installation cost experience, I sorted different size PV projects based on their installation dates and costs and then estimated the average installed cost after screening out the highest cost projects. To reflect efficient installations, I eliminated one-third of the projects with the highest costs and for projects of 150 kW and less only considered those that were installed since the first quarter of 2009. There were only eleven projects larger than 150 kW, so I decided to not screen these larger projects based on their installation date. There were only four greater than 150 kW projects installed after the first quarter of 2009. These greater than 150 kW projects installed after the first quarter of 2009

generally had lower costs so the decision to not screen these projects based on their installation date resulted in a higher cost estimate.

Given the significant PV price reductions that have been experienced in 2009 (reported to be from 20 to 50%) I assumed another 5% reduction in project costs to reflect the likelihood that additional cost reductions can be realized that are not reflected in the MTC database given lags associated with when project costs are established.

The largest project installed in the MTC database was about 400 kW. I used the costs for the largest class of projects in the database to estimate the installed cost for a 2.2 MW project, but assumed an additional 5% savings in the $/kW cost to reflect economies of scale offered by a 2.2 MW project.

**Q. You offered different estimates for the debt term and cost of debt for farm methane projects than were used for the other renewable energy technologies evaluated. Can you provide support for these estimates?**

A. Certainly. A debt term of seven years was proposed by the Vermont Agency of Agriculture, Food and Markets (Agency of Agriculture) for farm methane projects. This debt term was considerably shorter than that assumed for the other generation technologies. I assessed the reasonableness of this term by contacting various individuals who have experience with farm lending. These individuals confirmed the representation made by the Vermont Agency of Agriculture that a farm methane project would likely be financed using more conventional real estate loans with the collateral based on farm real estate. However, they indicated that the duration of the loan can approach the term of power purchase agreement and that lenders may look more favorably on such a loan than a conventional real estate loan since the investment would be generating positive cash flow. The agricultural lending expert from Yankee Farm

Credit that I spoke to noted that consideration also would be given to the useful life of the equipment, in particular to the reciprocating engine (gen set) and the risks that this posed.

With the collateral based on real estate, the interest rates on these loans will be similar to those offered for conventional real estate loans to farmers. Given the uncertainty regarding the useful life of the gen set under these applications, I estimated that a ten-year loan term was reasonable. The debt service coverage ratios also begun to drop below 1.0 at ten years for the smaller size projects suggesting that a longer term loan could drain cash from other uses. With the loan based on real estate which has a clear market value, a term of seven years, and on current credit market conditions, I estimated that an interest rate of 5.5% was reasonable.

**Q. Does this conclude your direct testimony?**

A. Yes.