Docket BRD-E-R-10

NOVA SCOTIA UTILITY AND REVIEW BOARD

In the Matter of: The Electricity Act and a hearing to determine Renewable Energy Community Based Feed-in Tariffs

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE CONSUMER ADVOCATE

Resource Insight, Inc.

MARCH 17, 2011

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I. Identification & Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water St, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than 250 times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty states and five Canadian provinces, and two U.S. Federal agencies. This testimony has included the review of many utility-proposed power plants and purchased-power contracts.

Q: Have you testified previously regarding rates for utility purchases from non-utility generators?

A: Yes. I have testified in at least nineteen proceedings on non-utility purchase rates, including the following:

- Massachusetts DUP 19494 Phase II (1979), on co-generation rates.
- Massachusetts DUP 535 (1981), on generic rules for setting rates for quailfying facilities (renewables and cogenerators).
- Massachusetts DUP 84-276, on contract rates for qualifying facilities.
- Massachusetts DUP 88-19, on rates for power sales from a cogenerator to Western Massachusetts Electric.
- Massachusetts DUP 88-123, on Western Massachusetts Electric avoided costs.
- Massachusetts DUP 89-239, estimation of externality values in supply planning and procurements.
- Massachusetts DUP 89-141, 90-73, 90-141, 90-194, and 90-270, on the treatment of externality values in purchases from non-utility generators.

- Massachusetts DUP 91-131, updating externality values.
- Ontario Environmental Assessment Board Ontario Hydro Demand/Supply Plan Hearings (1992), on environmental externalities.
- Texas PUC 110000 (1992); on the environmental effects of a purchase of cogenerator energy by Houston Lighting and Power.
- Maryland PSC 8473 (1992), on evaluating Baltimore Gas and Electric's power purchase from AES Northside.
- Maryland PSC 8179 (1993), on Potomac Edison's proposed purchase from the AES Warrior Run coal-fired cogenerator.
- New Jersey BRC EM92030359 (1994), on the environmental costs of a proposed cogenerator.
- North Carolina Utilities Commission E-100 (1995), Sub 74, Duke Power and Carolina Power & Light avoided costs for small hydro facilities.
- Connecticut DUPC 05-07-18, on the financial effect of long-term power contracts.
- Connecticut DUPC 07-04-24, reviewing capacity contracts with non-utility projects.
- Connecticut DUPC 08-01-01, reviewing proposed peaking generation projects.
- Ontario EB-2007-0707, on the Ontario Power Authority integrated system plan, including the valuation of renewable energy supplies.
- Nova Scotia UARB P-172, on the proposed NewPage Pt. Hawkesbury biomass project.

Q: Have you previously testified before this Board?

A: Yes. I testified in the Board's review of the following cases:

- Nova Scotia Power's Demand Side Management Plan for 2010 and Demand Side Management Cost Recovery Rider in May 2009,
- the proposed purchased-power agreement between Nova Scotia Power Inc. ("NSPI") and a biomass project to be constructed at the NewPage Pt. Hawkesbury ("NPPH") pulp and paper mill (NSUARB P-172),
- Nova Scotia Power's proposal to build the biomass project at NPPH (NSUARB P-128.10),
- Heritage Gas's 2010 rate case (NSUARB NG-HG-R-10).
- Nova Scotia Power's proposal to increase production depreciation rates (NSUARB NSPI-P-891).

II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the Nova Scotia Consumer Advocate.

Q: What is the purpose of your testimony?

A: I review the basis for the draft tariffs for Community Feed-In Tariffs (COMFITs) developed by the Synapse Energy Economics team and summarized in Exhibit B-1. In particular, I question the way in which Synapse incorporated, or failed to incorporate, the concept of "community" in estimating the cost of COMFIT projects. In addition, I compare Synapse's estimate of the cost of large COMFIT wind projects with the prices of similar-size market-based wind projects bid in response to NSPI's requests for proposals for renewable-energy projects.[1]

[1] Large COMFIT wind projects are in the same size range as the small wind projects NSPI has contracted for through the 2008 RFP and similar mechanisms.

Finally, I compute the rate effects of the proposed COMFIT tariffs, under a range of possible levels of COMFIT development.

Q: Please summarize your review of the Synapse proposal.

A: I have two major complaints about the Synapse report, and a few minor points. The first major point is that Synapse did not interpret its charge from the Board to include such important issues as the amount of capacity that might be developed under the tariffs or the resulting rate effects. As I result, I have performed my own analysis of potential rate effects. As discussed in Section VIII, I find that a vigorous COMFIT program at the rates proposed by Synapse could result in substantial rate increases.

My second major concern, discussed in Section IV, is that Synapse interpreted the concept of "community" to exclude any real community support for the projects and assumed that community ownership could only be a detriment to project development. Consequently, Synapse overstates financing and other costs of community projects. Synapse's failure to recognize the benefits of community ownership and support also seems to account for Synapse's failure to recognize the large gulf between proposed large-wind price and the prices NSPI is paying for energy from comparable-size wind projects under competitively-sourced contracts, or between Synapse's proposed rates and those in effect in other jurisdictions, as I discuss in Section VII.

With a handful of exceptions, Synapse's analysis generally appears to be technically competent. The inputs generally appear to be reasonable, to the extent that single input values can be representative of such varied situations as small hydro and biogas cogeneration, and for the still-developmental in-stream tidal technologies. Nonetheless the Board should be concerned about the following problems:

- an error in computation of the biomass rate, which I discuss in Section III.
- the capacity factor for large wind, which I discuss in Section IV.
- the assumptions related to community support (wind and hydro financing, property taxes, and development costs), which I discuss in Section V.

Q: What rates do you recommend for the COMFIT technology categories?

A: As I explain in Section IX, I recommend the COMFIT rates shown in Table 1, based on combining the effects of the following adjustments and considerations:

- a corrected biomass formula,
- a realistic capacity factor for the large wind projects,
- lower-cost capital for wind and hydro due to community support,
- property-tax relief for hydro projects,
- reduced development costs for community-supported projects,
- lower expected return for demonstration tidal projects.

Table 1: Comparison of Synapse-Proposed and Recommended COMFIT Rates
(Dollars per MWh)

	Synapse Proposal		Recommendation	
Technology	Fixed	2012 Variable	Fixed	2012 Variable
Small Wind	$452		$400	
Large Wind	$139		$102	
Biomass CHP	$94	$62	$94	$56
Hydro	$140		$114	
Tidal	$652		$381	

Q: What restrictions should be placed on the COMFIT rates when tariff sheets are prepared?

A: I suggest two such restrictions. First, it should be clear that no project will be eligible for COMFIT if it might result in power flowing backwards in the distribution substation, from the distribution side of the transformer to the transmission side. Second, the total capacity on the tidal COMFIT rate should be limited to minimize the effect on customer bills. I propose a limit of 3.5 MW, which would be sufficient for several demonstration projects and would limit the total rate effect to be similar to the small wind category, which is limited by regulation to 5 MW total.

III. Error in Biomass Computation

Q: What error did you find in Synapse's computation of the biomass rate?

A: Even given all of Synapse's assumptions, I believe that the recommended rate is too high. Synapse computed a levelized rate that would produce Synapse's intended 13% return cover all fixed costs and the escalating fuel and O&M costs. In other words, the $156/MWh is not the starting point for escalation. It is the appropriate price for the contract term, if fuel prices rise at 1.92%, along with O&M.

Synapse then proposes to escalate the levelized fuel price of $62/MWh at its recommended fuel escalator: 75% of 90% of CPI inflation (excluding energy) and 25% of diesel inflation. Instead, Synapse should have proposed to escalate the first-year fuel cost ($55.6/MWh).

The first-year price (again, using Synapse's input assumptions) should be $149.5/MWh, with $93.9/MWh subject to escalation and $55.6/MWh fixed.

Q: How much might the Board expect the proposed fuel escalator to rise over time?

A: In the 2010 Annual Energy Outlook (AEO 2010), the U.S. Energy Information Administration projects an average real escalation rate of 1.67% for commercial distillate, from 2012 through 2032. Combined with the 1.92% general inflation rate used in the Synapse analysis, diesel would rise at 3.63% nominal, assuming AEO 2010 is correct and that Canadian prices track U.S. prices. Weighting the diesel escalator 25% and the general inflation rate 75% produces a forecast biomass inflation rate of 2.2%.

In this case, the Synapse proposal would, inadvertently, apply an effective fuel escalation rate of about 4.2%.

IV. Large COMFIT Wind Capacity Factor

Q: What capacity factor underlies Synapse's proposed rate for wind projects over 50 kW?

A: Synapse uses 31%, which is the average of a 30% value suggested by wind developers (apparently without any documentary support) and a 32% value taken from the Hatch report (2008).[2] Synapse notes that Hatch reported that "capacity factors in four of the six zones studied range from 31% to 35%, and that in two zones the capacity factors are higher" (but strangely fails to note that the higher capacity factors are nearly 44%), and describes the Hatch estimate as "conservative."

Q: Is Synapse correct in its characterization of the Hatch report?

A: I think not. While Synapse claims "Hatch conservatively uses a capacity factor of 32% for their energy estimates," Synapse does not specify where in the 200-page Hatch report it found the 32% capacity factor value.[3] The range of capacity factors that Synapse cites are from Hatch's Table 4-2, which reports annual capacity factors as follow:

[2]Hatch, Nova Scotia Wind Integration Study, prepared for the Nova Scotia Department of Energy, 2008.

[3]I cannot find any reference to the term "conservative" in the Hatch report, so that characterization is apparently Synapse's opinion, rather than Hatch's.

- West: 33.35%
- Valley: 34.59%
- Truro: 31.86%
- Pictou: 31.86%
- Canso Strait: 43.59%
- Sydney: 43.59%

Hatch's Table 4-3 shows Hatch's estimates of capacity factors of various levels of future wind power. It applies those zonal capacity factors and finds average capacity factors for future wind resources varying from 33.4% for the lowest penetration scenario (311 MW, essentially the level now under contract) with development concentrated toward Pictou and Truro, to 36.71% with 961 MW of wind and development concentrated toward the Valley zone.

The only reference to a 32% capacity factor I can find in the Hatch report is in Chapter 3, involving the firm capacity credit for wind. Hatch does state ([. 3-4) that "the firm capacity of the future wind plants was calculated based on a presumption of 32% annual capacity factor." In fact, Hatch used 32% as the ratio of firm capacity to nominal capacity, so this may be a typographical error.[4]

In any case, when Hatch computed average capacity factors, it derived values greater than 32%.

Q: What is "conservative" about selecting a capacity factor biased to the low end of the range?

A: Nothing, from a public-interest perspective. In engineering, a "conservative" estimate is one that is intentional biased in the direction that provides a margin of safety, such as understating the strength of materials or overstating the likely

[4]Indeed, on page 2-1, Hatch refers to "the presumption of 32% firm capacity contribution."

number of dancers in a ballroom. Selecting a low estimate of capacity factor does not protect consumers; it unnecessarily increases prices.

The only sense in which this particular decision could be considered to be conservative (as Synapse uses that term on page 21, lines 31–32, of Exhibit B-1) would be from the perspective of developers.[5]

Q: What would be a realistic estimate of capacity factor for large COMFIT wind projects?

A: For the distribution-connected wind plants installed after 2007, NSPI's reported energy output forecasts imply capacity factors that average 37%. Only two of the eleven plants are expected to have capacity factors smaller than Synapse's 31% estimate.

Interestingly, the eleven earlier (2005–2007) small wind units owned by or selling to NSPI have an average capacity factor of 26%. Developers seem to be getting better at identifying good wind sites.

Q: How much lower would the COMFIT rate be with the 37% average capacity factor, rather than Synapse's intentionally understated 31%?

A: Substituting the 37% capacity factor into the Synapse spreadsheet reduces the required COMFIT rate for a taxable owner from $142/MWh to $119/MWh, and for a non-taxable owner from $136/MWh to $114/MWh; the average required rate would fall from $139/MWh to $117/MWh.

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[5]On page 23, line 7, of B-1, Synapse uses "conservative" to describe Hatch's choice of a low capacity factor to lean in the direction of understating energy output; in that very different application, the low capacity-factor assumption would protect the Province from overstating wind-energy potential.

V. Benefits of Community Support for Renewable Power Projects

Q: How does the Synapse team view the effect of community involvement in development of COMFIT projects?

A: Synapse assumes that community involvement adds to the costs of project development, and ignores almost all the benefits of community-based development. Synapse accepts that community-based ownership requires more debt than commercial projects (Exhibit B-1, p. 12). Synapse also asserts that majority ownership by a community-based group requires that COMFIT rates be higher than FIT rates in Vermont, for small wind (Exhibit B-1, p. 20), large wind (p. 23), biomass (p. 27), and hydro (p. 32).[6]

In the following places in Exhibit B-1, Synapse essentially assumes that the COMFIT investors would be motivated and behave exactly like investors in capital markets:

- Synapse bases interest rates on debt entirely on the rates that commercial lenders suggested they would require for financing COMFIT projects (p. 12).
- Synapse assumes that the cost of capital will be higher for COMFIT projects because "investors who buy utility stocks rely on the utility's diversified portfolio of resources…[while] most investors in organizations developing a COMFIT project would be investing, at least initially, in one project" (p. 15).

[6]Synapse's position that community ownership burdens COMFIT biomass projects is curious, since the project can be majority owned by the steam host (e.g., a sawmill) and the minority owned by anyone. Indeed, any COMFIT project can be owned up to 49.9%, and managed, by any party, including the parties Synapse expects to own small FIT projects in Ontario and Vermont.

- "For projects owned by community-based groups, investors are likely to see project size risk, portfolio risk and, for some community-based groups, risk due to inexperience" (p. 15).
- "In the case of projects developed by municipalities and universities, investors are likely to perceive less risk due to inexperience with energy projects, or perhaps even none" (p. 15).
- "In the case of a new non-profit or CEDIF or a first energy project by a First Nation, investors are likely to see significant risk due to inexperience" (p. 15).
- "If tidal developers put up their own equity, we believe they should receive a return well above the NSPI rate for taking on these risks, and if developers seek outside equity, they will probably have to show very high expected returns relative to NSPI to attract capital" (p. 16).

None of these passages describes the purposes, decision-making, or return requirements for community members or institutions in renewable energy projects. Indeed, many of these passages ignore entirely community ownership, or assume that community investors are indistinguishable from private equity funds or investment banks.

Synapse concludes that the 13% return on equity allowed for Heritage Gas is a reasonable target for most COMFIT resources. Heritage Gas was funded by Alberta's AltaGas, as a straightforward investment to generate profits, without any social, environmental or community concern. Heritage Gas is essentially the polar opposite of a community renewable project.

Synapse also assumes that, despite the nominal designation as a community renewable project, these renewable plants would receive no material support from the local community and would be assessed property taxes like any commercial enterprise.

Q: What benefits would a community renewable project have, compared to a commercial development?

A: A truly community-based project would benefit from municipal, university or community financing; the donation of land and services; and property tax relief.

Q: How would the financing of a community project differ from financing of a purely commercial enterprise?

A: A truly community-based project would expect financial support from the community. That may be in the form of donations or low-cost financing from some combination of the local government, the citizenry, and local institutions.

Synapse assumes that no one will invest in community renewable projects unless they are promised returns commensurate with returns available from corporate stocks and bonds of equivalent risk. Since Synapse assumes that community projects are very risky, the assumed returns are 8% of debt and 13% on equity, with 15% return on equity required for tidal plants.

Contrary to Synapse's assumption, municipalities can and do raise debt capital at less than 6%, and there is no reason to suppose that they could not do so for a municipally financed renewable project. Universities generally finance capital projects, especially projects that are highly visible and well regarded, through donations from alumni, wealthy individuals, and corporations.

As for local individuals and institutions, they frequently donate money to support causes they believe in, earning a direct financial return of -100% (or something a little less negative if the donation is offset by an income-tax deduction). This is how construction of community centers and libraries are typically funded, with a combination of individual and corporate contributions and local government support. Certainly, a supportive community will invest in a project at returns lower than full market rates, but higher than rates available to small investors. If they are unwilling to do so, the project clearly does not have community support, and is simply a commercial project.

Q: Are you familiar with the financing of community energy projects?

A: Yes. In Massachusetts, a program was established under which a state agency matched funding from local contributors to install panels on school buildings. I personally contributed to two rounds of project funding in my home town, Lexington; the response to the public appeal for the first array was so enthusiastic that the sponsors decided to fund a second array. Eleven other communities also raised enough money to participate in this or similar programs and install panels.

Many of the people who contributed tens or hundreds of dollars could equally well have invested thousands of dollars if they were likely to get their money back, especially with a return comparable to what they would otherwise earn.

Other examples of community financing of renewable energy projects include:

- The Sakai Intermediate School in Bainbridge Island, Washington, raised $30,000 in contributions to purchase and install solar panels.
- The Clean Energy Collective of El Jebel, Colorado, organized about 20 members to purchase solar panels at $3,150/kW (after all rebates and tax credits), with the power to be sold to the local utility at 11¢/kWh. Assuming an 18% capacity factor and no maintenance costs, the internal rate of return for the owners is 1% if the panels last 20 years and 3% if the panels last 25 years.
- The Appalachian Institute for Renewable Energy installed a PV system financed by seven to 10 individuals, who paid $1,700/kW (after incentives)

and sell energy to AIRE at under 10¢/kWh. At a capacity factor is 17%, with no escalation in the sales price, the IRR would be 7%–8%; with 2% escalation, the IRR would be 9–11%.

Q: What return can consumers earn on standard fixed-income investments?

A: Currently, some Canadian banks are offering 5-year GICs at 2% interest rates. At least one on-line bank, ING, offers 3% interest on a 5-year GIC.

Q: What returns would you expect to be required to attract capital from community members?

A: If community members are not willing to invest in the project at interest rates of 5% or 6%, or expected equity returns of 10% or 11%, they must not be very interested in the project. As one of the parties advocating for COMFIT investments said in an email to the service list in this proceeding,

> Economically speaking, individuals have savings that they invest in interest-earning activities. Those savings, if made available for clean energy generation, could really assist the revolution we need in our energy systems. (Janice Ashworth, email "Re: Full cost accounting: how renewables should be assessed!" to COMFIT parties, March 5, 2011)

Offering a 6% interest rate should certainly make available a large amount of savings, if local individuals are favorably disposed towards the project.

Q: What sort of in-kind donations would a community project generally expect?

A: Three types of in-kind donations seem likely. One important likely contribution to a community project would be donation of land and access, either by the local government or a community member or organization.

Eliminating the land lease expense assumed by Synapse would reduce the hydro rate by $0.7/MWh, of large wind by about $4/MWh, and tidal by $2/MWh.

Second, community projects, such as construction of parks and playgrounds, often benefit from the use of the staff and equipment of the municipal public works department, such as for construction of access roads and delivery of construction materials. Local suppliers and contractors also often contribute labor, equipment and materials, either free or at cost.

For community renewables projects, major parts of the installation process are likely to be beyond the capabilities of local firms, but grading access roads, erecting utility poles and stringing conductor for the customer portion of the interconnection, fencing the construction area, and delivering and pouring concrete and gravel, may all be within the capability of public and local community organizations. The entire process of erecting a small wind turbine may be within those capabilities.

The amount of in-kind support will vary widely among projects, depending on local capabilities and the details of the project.

Third, local government and volunteers can substantially reduce development costs, by scouting sites, conducting economic feasibility studies, drafting incorporation documents and contracts, and by handling fundraising, licensing and permitting, and outreach to abutters and the community.

Cutting Synapse's estimate of development costs by 25% would reduce the revenue requirement for large wind by $5/MWh and tidal by $28/MWh. Synapse does not break out development costs for small wind and hydro.

Q: Why would a community project expect property-tax relief?

A: If the local town or municipality owns the project, it would not tax its project any more than it would tax its schools. Similarly, if local residents (and voters) are pursuing a renewable-energy project, waiving property tax is an easy way for local government to support the project without any expenditure of public funds.

Q: How much might that property-tax relief be worth?

A: The effective property tax rates are very low on all the technologies modeled by Synapse, except for hydro. For the Synapse hydro project, property-tax exemption would reduce the required COMFIT tariff by $14.5/MWh.

VI. The Cost of Capital for Tidal Projects

Q: What cost of capital did Synapse assume for tidal projects?

A: Synapse assumed 100% equity financing at 15% return on equity.

Q: Does this capital structure represent a community project?

A: No. Synapse's discussion of the financing of tidal projects makes it clear that the capital structure represents a market-based commercial venture.

Q: Would you expect any tidal projects connected to the Nova Scotia distribution system in the next few years to be commercial ventures?

A: No. Tidal power generation is in the development-and-demonstration phase. Technology manufacturers cannot expect to make competitive returns on the equipment they are currently installing. The payback on these early, limited-run (sometimes unique) models is in information and reputation, rather than revenues.

For example, Verdant has been demonstrating its tidal technology—now in its third generation of test turbines—at its Roosevelt Island in New York's East River. Verdant has been selling its power to a nearby supermarket and parking garage. While New York City electricity prices are higher, it is doubtful that Verdant is getting much more than $200/MWh for its power, compared to the

$652/MWh recommended by Synapse. Unless Synapse's estimate of the cost of building and running tidal plants is grossly overstated, Verdant would be lucky to be recovering its investment in its demonstration project, let alone earning a return.[7]

Q: What equity return might be appropriate for tidal projects in the COMFIT computation?

A: If the COMFIT includes a 6% after-tax equity return, it would be more than a tidal-equipment manufacturer could expect to earn on projects elsewhere. The resulting rate of about $398/MWh would still be about twice what Verdant received in New York, and about four times the rate that a demonstration tidal project would receive in British Columbia under the Standard Offer Program.

VII. Reality Checks

Q: How can the Board assess the reasonableness of the COMFIT rates proposed by Synapse?

A: The Board should compare the proposed COMFIT rates to rates in similar programs, especially if those programs have attracted applications from projects of the scale and technologies eligible for COMFIT. If projects have been proposed and built in other jurisdictions in response to a certain rate, that rate is also likely to support development of COMFIT projects in Nova Scotia, all else equal.

A second approach is to compare the proposed COMFIT rates to the prices offered in response to NSPI's past renewables RFPs. Unfortunately, this comparison is largely limited to projects comparable to the large COMFIT wind

[7] This is even before the environmental studies that Verdant undertook at Roosevelt Island to support the licensing process for future projects.

projects, which have been bid into the RFPs. This test is especially valuable since it applies directly to non-utility projects developed in Nova Scotia.

A third approach is to compare the proposed COMFIT rates to the cost of renewable projects developed by NSPI.

A. Comparison to Other Jurisdictions

Q: How do the proposed COMFIT rates compare to those in other jurisdictions?

A: Synapse's proposals are consistently priced higher than those in other jurisdictions, except for the large-wind rate, which is slightly lower than the Ontario rate.

Table 2 compares the Synapse-proposed rates to the biomass, hydro, and wind prices for small generators offered by the Ontario Feed-In Tariff (including the micro-FIT for projects under 10 kW), the British Columbia Hydro Standard Offer Program, and the Vermont SPEED program. Synapse's proposed rates are in 2012 dollars, while those for Ontario and British Columbia are in 2010 dollars and would inflate to the project start date. The BC rates do not vary by technology, but do vary by location.

In each category, BC Hydro will also pay up to $150/kW of interconnection costs, which is equivalent to several more dollars per MWh in tariff payment. Since the BC rates are much lower to start with, including the interconnection costs would still leave the BC prices well below those of the other jurisdictions.

Table 2: Comparison of Existing and Proposed FIT Rates

Technology and Size	Jurisdiction	Starting Price $/MWh	Percent of Price Escalating with Inflation	Levelized Price 2012$/MWh	Potential Community Adder
Biomass					
unknown	Nova Scotia (SEE)	$156	30% at 0.9×CPI 10% at diesel	$166	
≤ 10 MW	Ontario	$138	20% at CPI	$147	$4
≤ 15 MW[a]	British Columbia	$95–104		$99–$108	
≤ 2.2 MW	Vermont	$125	Levelized	$130	
Hydro					
unknown	Nova Scotia (SEE)	$140		$140	
≤ 10 MW	Ontario	$131	20% at CPI	$140	$5
≤ 15 MW	British Columbia	$95–104		$99–$108	
≤ 2.2 MW	Vermont	$123	Levelized	$128	
Small Wind					
≤ 50 kW	Nova Scotia (SEE)	$452		$452	
≤ 100 kW	Vermont	$215	Levelized	$223	
Larger Wind					
> 50 kW	Nova Scotia (SEE)	$139		$139	
All	Ontario	$135	20% at CPI	$144	$10
≤ 15 MW	British Columbia	$95–104		$99–$108	
> 100 kW < 2.2 MW	Vermont	$118	Levelized	$123	

Sources: Vermont prices from Vermont PSB, Docket 7533, 1/15/2010 Order, Attachment II. BC prices from "Standing Offer Program (SOP): SOP Changes and Process Review," February 23, 2011. Ontario prices from FIT Price Schedule, August 13, 2010. Aboriginal adder is 50% greater than community adder.

Notes
[a]The BC Standard Offer Program was limited to 10 MW installations until 2010.

Figure 1 and Figure 2 show these prices in levelized 2012 dollars. For the diesel part of the Synapse-proposed biomass fuel escalator, I added NSPI's 1.92% forecast of general inflation to the 1.7% real escalation rate forecast for 2012–2032 in the US Energy Information Administration's Annual Energy Outlook, to get 3.6% nominal inflation.

Figure 1: FIT Rates Excluding Small Wind

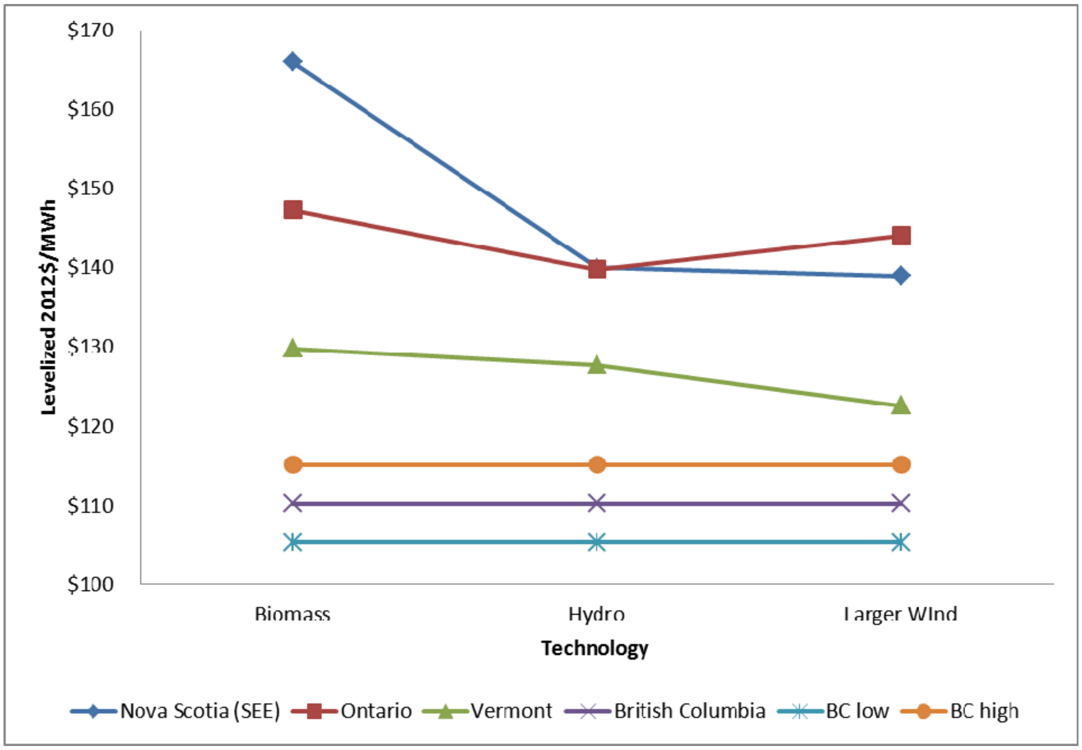
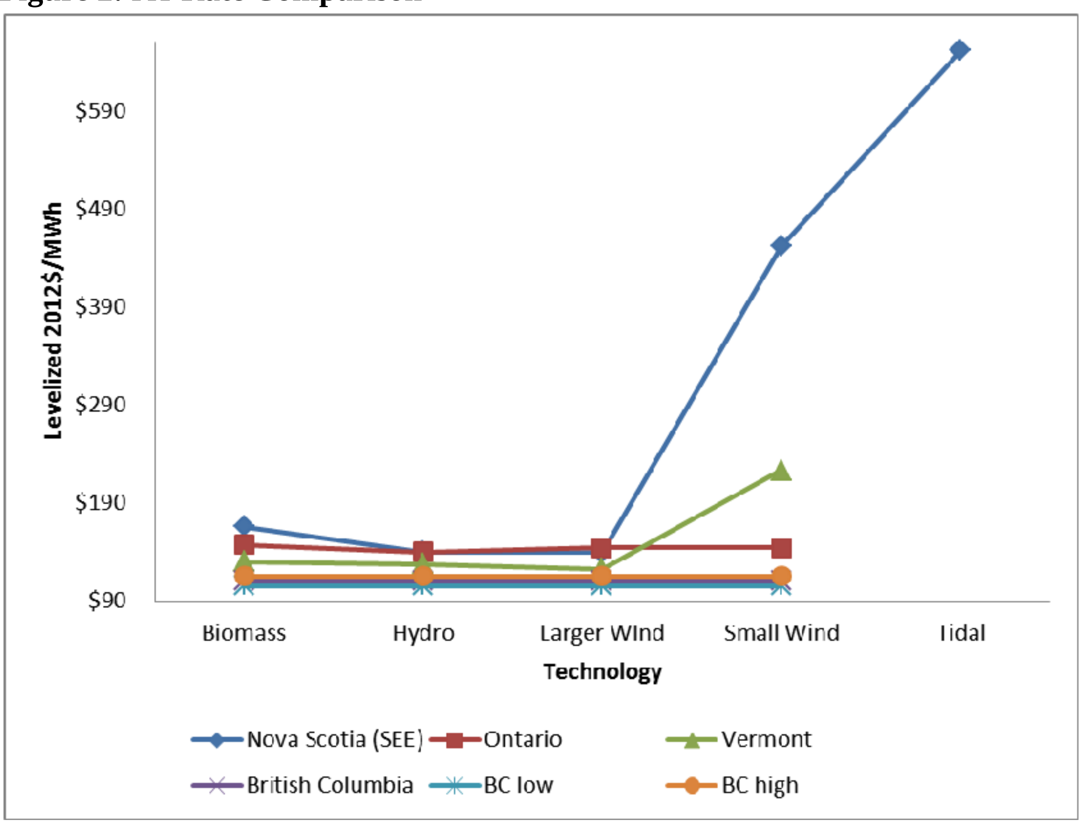


Figure 2: FIT Rate Comparison



Q: Have these lower prices led to offers from small renewable projects?

A: Yes. I have not been able to find any detail on the BC standard-offer projects. As of November 1, 2010, BC Hydro reports the following projects:[8]

- Five hydro projects averaging 7 MW under contract. One of these is Regional Power's 20-MW Bear Hydro Project, implying that the remaining projects average less than 4 MW.
- One biogas project of 1.3 MW under contract.
- Twelve pending hydro applications averaging 7 MW.
- One pending biomass application of 5 MW,
- One pending biogas application of 0.3 MW.

In contrast, Vermont identifies individual FIT projects. Applications have included the following projects:

- 9 biomass projects, ranging from 400 to 2,200 kW.
- 21 wind projects, ranging from 100 to 2,200 kW.
- 14 hydro projects, ranging from 50 to 2,200 kW

Some of these projects have since been withdrawn or downsized, perhaps due to interconnection constraints. More biomass projects might have been offered, but the first day's applications exceeded the 12.5 MW allowed for biomass projects. The initial oversubscription of the total 50 MW FIT cap may have also discouraged additional applications.

The Ontario Power Authority provides Bi-Weekly FIT and microFIT Reports that summarize the number and capacity of projects by technology and status. Unfortunately, the data on the distribution of project size are limited. The OPA reports do provide the number and capacity of projects by technology in the "allocation-exempt" group, which include distribution-connected units up to

[8]Standing Offer Program: Report on the SOP 2-Year Review, BC Hydro, January 2011, p. 2.

250 kW or 500 kW, depending on the distribution voltage, and the total number and capacity of applications under the micro-FIT, which is limited to projects up to 10 kW. Projects in all three categories (micro-FIT, allocation-exempt, and other) receive the same prices, but the approval process is simpler for the smaller projects.

On the micro-FIT, OPA reports about 26,000 applications and states that only about 1% are not solar projects. That leaves some 260 projects for the other technologies; most of these are likely to be very small wind turbines.

In the allocation-exempt group, OPA reports 5 biomass projects (two at 100 kW each and one at 300 kW), 7 hydro projects (totaling 1.6 MW), and 13 wind projects (totaling 3.2 MW).[9]

Above the "allocation-exempt" group, it is not generally possible to determine the size of individual projects, since OPA reports only the total number of units and total MW in each progress category. As of the February 18 2011 report, the three hydro units in the "submitted" category averaged about 2 MW apiece, and the one listed as "application complete" had a capacity of 1 MW. The nine projects withdrawn or rejected (perhaps due to transmission problems) averaged 2 MW. The 73 hydro projects awaiting connection approval or under contract averaged about 4.5 MW; some of them were likely to be small enough to connect to distribution, as well.

The average Ontario biomass and wind FIT projects are too large to connect to distribution; it is not clear how many small projects are lurking in the aggregated data. By tracking changes in status, I have identified a few examples. In the November 9 report, one hydro unit of about one MW submitted an application, while another unit of similar size moved to the "contract executed"

[9] I excluded projects that were listed as withdrawn or rejected.

category, and two wind projects totaling 3 MW applied. In the November 22 report, a 2 MW biomass unit failed the connection review.

B. Comparison to Nova Scotia Power's Procurement Results

Q: What NSPI RFP results can be used in testing the reasonableness of the Synapse-proposed COMFIT rates?

A: Eleven recent wind projects are under contract to NSPI, most from the 2008 RFP for distribution-connected renewables.

Table 3: Small Recent RFP Wind Plants

Project	MW	In-Service Date
Cape North	0.65	31-Dec-10
Spiddle Hill (distribution)	0.80	31-Dec-11
Watts Section, Sheet Harbour	1.50	31-Dec-10
Donkin Wind Farm	1.60	1-Jul-10
Granville Ferry Wind Power Project	2.00	31-Dec-10
Isle Madame Wind Power Project	2.00	31-Dec-10
Dunvegan Wind Power Project	2.00	31-Dec-10
Creignish Rear	2.00	31-Dec-11
S. Cape Mabou	2.00	31-Dec-11
Irish Mountain	2.00	31-Dec-11
Fairmont Wind Farm	4.00	1-Jun-12

Sources: Point Tupper Wind NSPI (Avon) IR-3 Attachment 1 and NSPI (CA) IR-3 Attachment 1; Fairmont Wind Farm website.

In the first table and figure in Confidential Exhibit PLC-2, I show the contract price for each of these projects, as well as the average price.

Q: Are any adjustments in these prices necessary before comparison to Synapse's proposed rates?

A: Yes. The bid prices for the 2010 projects can be presumed to be reduced by about $7.5/MWh, the levelized value of the ecoEnergy credits available for most renewable projects that enter service before March 2011. The developers of these units may have discounted the value of the ecoEnergy credits, since neither operation before March 2011 nor continued availability of the credits would have been certain at the time of their bid preparation. While I add back $7.5/MWh for the 2010 projects in Exhibit PLC-2, that may overstate this adjustment.

Second, the cost of turbines, towers, and installation has fallen since the 2008 peak, due to reduced demand for turbines and commodities and increased global manufacturing capacity. As Synapse observes, "We estimate that our project costs are roughly 11% lower than 2008 project costs, consistent with data showing falling turbine prices since that time" (Exhibit B-1, p. 22). As shown in Exhibit PLC-2, reducing the bid prices 10% just for the projects expected to enter service in 2010 more than offsets the loss of the ecoEnergy credits.

Third, offering a known feed-in tariff to all eligible facilities should reduce the risk of development, compared to preparing a proposal in response to an RFP, without any assurance that your project will be selected. This reduction in risk should translate into a reduction in price. I have not estimated this effect, but it is one more reason that my adjusted RFP prices may still be overstated compared to conditions facing COMFIT projects.

Fourth, these prices represent for-profit commercial financing, without the benefits of municipal or community financing, donation of land, or property tax relief.

The first two adjustments are reflected in the second table and figure in Exhibit PLC-2.

Q: Did you make any other adjustments?

A: Yes. As a sensitivity, I adjusted the projects with 2011 in-service dates for the reduction in input prices, as described above for 2010 projects. I cannot tell when these projects locked in their input prices. The results are shown in the third table and figure in Exhibit PLC-2.

Q: What do you conclude from these comparisons?

A: I have three observations. First, the $139/MWh proposed by Synapse for large COMFIT wind projects is much higher than the actual prices in the contracts for recent RFP wind projects of comparable-size units, and even further above those contract prices when they are adjusted to current conditions. The Synapse proposal would need to be reduced substantially (i.e., by well over 10%) to be consistent with the actual bids.[10]

Second, NSPI has rejected a number of projects, including some that would have connected to distribution, that offered prices lower than the Synapse proposal.

Third, no economies of scale are evident over the range of unit sizes for which we have data. While at least one commenter expressed concern that a price set for a 2 MW project might be inadequate to support a 600-kW project, the bid data indicate that costs are quite stable over this range.

C. Comparison to Nova Scotia Power's Wind-Project Costs

Q: What levelized costs have NSPI estimated for the wind projects it owns?

A: The company reports that the Nuttby project will cost $84.54/MWh (Nuttby Application, September 2009, p. 16) the Point Tupper Wind Project will cost

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[10]Specific values are listed in Exhibit PLC-2.

$91.65/MWh (Point Tupper Application, February 23, 2010, p. 16), and that Digby will cost $86.71/MWh (Digby Application, July 23, 2010, p. 25). Even adding in $7.50/MWh for the loss of the ecoEnergy credit would leave these costs below $100/MWh; taking into account the decline in turbine prices, current costs for additional NSPI wind generation would be even lower.

VIII. Potential Rate Effects of COMFIT

Q: Please describe your analysis of the rate impacts from implementation of the COMFIT program.

A: I estimated the impact on the Company's system-average rate from the purchase of power from community-based renewable resources at the tariff rates proposed in Synapse's March 2, 2011 filing.[11] Specifically, I estimated the percentage amount by which the current system-average rate would increase in a representative year with purchases from a mix of small and large wind, biomass CHP, hydro, and tidal resources. My analysis accounted for both the increase in costs to the Company associated with COMFIT payments to eligible resources and the offsetting reduction in the Company's power-supply costs that would be avoided with purchases from COMFIT resources.

Q: How did you derive the current system-average rate?

A: I calculated the current system-average rate as total system revenues divided by total system sales. For both total system revenues and sales, I used the Company's forecasts for 2011 for the so-called "Above the Line" rate classes, as reported in the Company's December 10, 2010 Fuel Adjustment Mechanism

[11] I used Synapse's proposed tariff as filed, without corrections or adjustments.

compliance filing in Case No. P-887(2). Based on these forecasted amounts, I derived a system-average rate of $111.73/MWh.

Q: How did you estimate the change to the current system-average rate due to COMFIT projects?

A: I derived the rate impact from COMFIT purchases by estimating both the annual payments at COMFIT rates and the annual power-supply costs avoided with purchases from COMFIT resources.

I estimated total first-year COMFIT payments for the five cases listed in Table 4. In each case, I assume that the full five MW of small wind is subscribed, given the very high rate proposed. Case 1 includes only the small wind, to determine the effect of that component of the program. The other cases examine a mix of capacity and the following amounts for capacity are eligible for COMFIT payments. Cases 2–4 assume that COMFIT development will be limited to 100 MW, due to constraints on distribution capacity and the location of renewable resource potential.[12] Case 5 relaxes that assumption, assuming a total of 170 MW, which could result from any combination of the following:

- utilization of a higher percentage of available net minimum load,
- higher-than-forecast capacity factors (since an increase in capacity factor has the same effect on revenues as the same percentage increase in installed capacity),

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[12]Nova Scotia Power estimates that the sum of minimum loads on its substations, net of generation already installed on the feeders, is about 200 MW. Additional generation may be feasible on many feeders and substations, but if distribution-connected generation could exceed load, NSPI must analyze the effect of the back-flow on the transmission system. As I understand the situation, DOE does not intend to approve any COMFIT projects affecting the transmission system. Since not every substation serves areas well-suited for renewable project development, NSPI and DOE have assumed that only half the remaining substation capacity would be utilized.

- installation of controls on distributed generators to limit their output at minimum substation load.[13]

Table 4: COMFIT Cases (MW by Technology Group)

	Case Number				
	1	2	3	4	5
Description	Small Wind	Mostly Wind	Balanced	High Tidal	High Penetration
Small Wind	5	5	5	5	5
Large Wind		85	50	25	50
Biomass CHP		5	20	20	30
Hydro		4	20	20	35
Tidal		1	5	30	50
Total	5	100	100	100	170

I estimated total annual COMFIT payment for each case from Synapse's proposed rates and assumed capacity factors by resource types.

Q: What is your estimate for the offsetting reduction in other power costs associated with COMFIT purchases?

A: As with my calculation of COMFIT payments, I estimated annual generation from COMFIT resources based on my assumptions regarding eligible capacity and the capacity-factor assumptions provided in the Board Counsel's filing. I then derived three estimates of power-cost reductions using three different measures of the market value of COMFIT generation.

First, I estimated savings from COMFIT purchases assuming that such purchases would free up equivalent amounts of generation for sale in the export market. I valued those exports at NSPI's forecast for the average export price of $59.22/MWh, as reported in the December 10, 2010 Fuel Adjustment Mechanism compliance filing in Case No. P-887(2).

[13]This approach may be most feasible for biomass CHP, since minimum substation load will tend to coincide with times of inactivity for the host facility, such as early Sunday mornings.

Second, I valued COMFIT generation by assuming that such purchases would back down output from the Company's generation fleet, at the average cost of fuel. In principle, increased energy from renewable should back down the most expensive energy in each hour, but that may not be possible due to contract requirements and operating constraints. For the average price of fuel, I used the 2011 Base Cost of Fuel for the above-the-line rate classes of $46.12/MWh, as reported in the December 2, 2010 2011 Base Cost of Fuel compliance filing.

Finally, I valued COMFIT generation by assuming that such purchases would reduce the amount of renewable generation that NSPI would need to procure to comply with the Renewable Energy Standard. I assume that renewable purchases through RFPS would cost $110/MWh, roughly based on my analysis in Exhibit PLC-2.

I did not include any cost of integration of renewables. NSPI has assumed that integrating wind would cost $10/MWh (Port Hawkesbury Biomass Project Application, Appendix 8). That value is probably an over-estimate, but the value may not be zero, either. Any integration costs would increase the rate increases due to COMFIT wind that is not displacing other wind resources.

Q: Please summarize your findings regarding the net impact on system-average rates associated with COMFIT purchases.

A: The results of my rate-impact analysis, assuming the lowest avoided cost (average system fuel) and the highest system cost (RFP renewables), and using Synapse's proposed COMFIT rates, are summarized in Table 5.[14]

[14] I did not include in Table 5 the results with the export price, which are between the base fuel and RPF renewables cases, are close to the former.

Table 5: First-year COMFIT Rate Effects

	Case Number and Description				
	1 Small Wind	2 Mostly Wind	3 Balanced	4 High Tidal	5 High Penetration
Thousands of Dollars per Year If Avoiding					
Base Fuel	$4,089	$32,465	$49,124	$91,913	$151,058
RFP Renewables	$3,445	$13,755	$24,741	$66,690	$108,803
Rate Increase					
Base Fuel	0.3%	2.6%	3.9%	7.3%	12.0%
RFP Renewables	0.3%	1.1%	2.0%	5.3%	8.7%

These values will vary over the years, depending on the rate at which COMFIT projects are installed and the price of fuel.

In 2012–2014, the COMFIT resources would mostly back down existing resources, so the rate increase would be something like the "base fuel" values in Table 5. Since NSPI currently projects that it is currently short on renewable energy for meeting its 2015 and 2020 renewable obligations, as shown in Exhibit PLC-3, NSPI would be adding more renewables in 2015 and thereafter. Any energy provided by COMFIT projects would reduce the amount of market renewables NSPI purchases or NSPI-owned additions. Hence, the avoided supply from 2015 on would be the cost of non-COMFIT renewables.

The small wind capacity, by itself, has a relatively modest rate effect, which may be tolerable to facilitate the public-policy interest in allowing small public involvement in renewable energy. The larger COMFIT portfolios, especially those with large amount of tidal power, become quite expensive for ratepayers.

Q: Might these rate effects be justified to increase the amount of renewables in the NSPI resource plant?

A: No. NSPI will meet its RES targets, whether through COMFIT, RFPs, or NSPI ownership. Neither NSPI nor the Board has shown any interest in acquiring renewable energy in excess of the RES. If the government, the Board, or NSPI decide that additional renewable energy should be acquired, that energy should be acquired at minimum cost, while meeting any other related goals.

Q: If the Board wanted to increase NSPI's renewable supply, or reduce NSPI's use of coal, would COMFIT projects at Synapse's proposed rates be an efficient mechanism for achieving those goals?

A: No. For any given increase in customer bills (and the accompanying level of stress on consumers and the economy), Synapse's COMFIT rates would result in less renewable energy than alternative procurement approaches, including lower COMFIT rates, RFP procurement, purchases from new hydro facilities in Labrador, and NSPI construction.

The questions before the Board in this proceeding have to do with whether government targets for renewable energy, and reductions in emissions of carbon, mercury, or other pollutants will be achieved in a least-cost manner, or in an unnecessarily expensive manner, paying more for wind, biomass and hydro projects than they would get through an RFP and buying large amounts of tidal resources that cost many times as much as renewable alternatives.

Q: Are there any of the COMFIT technology categories that particularly concern you?

A: Yes. It would be difficult to justify imposing on consumers the exorbitant prices that Synapse proposes for small wind and tidal contracts, or even the reduced prices I summarize in Table 6. As I demonstrated in Section VII, the costs of purchased or NSPI-owned wind energy are a small fraction of the proposed small-wind and tidal COMFIT rates.

Even if the COMFIT projects were displacing the coal combustion, rather other renewables, it would be difficult to justify the proposed small-wind and tidal COMFIT rates compared to the combined financial and environmental costs of coal. In the consultation portion of this proceeding, Sierra Club Canada provided a study of the environmental costs of coal, which also included some information on subsidies.[15] The study's high-end estimate of externality costs is about $290/MWh in 2012 dollars; even adding that estimate to the $46/MWh average cost of fuel would not produce a total cost approaching the $452/MWh for small wind and $652 for tidal proposed by Synapse.

There may be other justifications for some amount of small wind (such as facilitating renewable projects that can be undertaken directly by households and small businesses, or distributing visible renewable-energy projects widely in the province) and tidal (such as attracting the nascent tidal-power to build demonstration projects, research facilities, and even production facilities in Nova Scotia).

Q: Do the Renewable Energy Regulations address the problem of these very expensive resources?

A: Only with respect to small wind projects, whose total COMFIT capacity is limited to 5 MW. I interpret the capacity cap as being intended to limit the potential rate effect of these uneconomic projects, while allowing at least 100 projects to be implemented province-wide, promoting other goals. Unfortunately, the regulations do not impose similar limits on tidal projects.

[15] Epstein, PR, "Full cost accounting for the life cycle of coal," in *Ecological Economics Reviews*, Annals of the New York Academy of Sciences, 1219: 73–98.

IX. Recommended Rates and Tariff Provisions

Q: Please summarize your recommendations regarding the COMFIT rates.

A: The corrections I was able to quantify in Sections III–VI are summarized in Table 6. The "corrected" line is generally greater than the sum of the values above, due to round-off and the interactions of the various adjustments.

Table 6: Summary of Corrections to Synapse's Rate Proposals,
Dollars per MWh

	Small Wind	Large Wind	Biomass	Hydro	Tidal
Synapse Proposed	$452	$139	$156	$140	$652
Adjustments					
Biomass formula			-$7		
Wind CF		−$22			
6% debt, 11% equity	−$52	−$13		−$7	
Development Return					−$254
Land Donation		−$4		−$1	−$2
Reduced Development Cost		−$5			−$28
Property-Tax Relief				−$15	
Total	−$52	−$44	−$7	−$22	−$284
Corrected	$400	$102	$150	$114	$381
Change	−12%	−27%	−4%	−19%	−42%

I was not able to quantify the effects of in-kind donations, although those may be very important for some projects, especially the small wind projects.

Q: Have you estimated that rate effects for the development cases you described in Section VIII?

A: Yes. Table 7 presents the rate impacts in the same form and with the same assumptions as in Table 5.

Table 7: First-Year Bill Effect, Corrected Rates

	Case Number and Description				
	1 Small Wind	2 Mostly Wind	3 Balanced	4 High Tidal	5 High Penetration
Thousands of Dollars per Year If Avoiding					
Base Fuel	$3,565	$24,392	$38,147	$60,755	$98,676
RFP Renewables	$2,921	$2,829	$12,085	$34,693	$54,743
Rate Increase					
Base Fuel	0.3%	1.9%	3.0%	4.8%	7.9%
RFP Renewables	0.2%	0.2%	1.0%	2.8%	4.4%

With the corrected COMFIT rates, the increases in customer bills are much more modest than with Synapse's proposed tariffs.

Q: What tariff language has Synapse proposed?

A: Synapse did not propose tariff language.

Q: When tariff language is developed, what provisions should be included?

A: The tariff should limit eligibility to projects that meet or exceed the following requirements:

- approval from the Energy Minister,
- the requirements of Section 20 of the Renewable Electricity Regulations,
- in the case of small wind, are within the 5 MW statutory limit,
- will not generate more than the minimum load on the substation serving the feeder to which the generator would connect, minus the capacity of generators already connected to the feeder.

While approval from the Minister should cover the second and third bullets, it is generally prudent to include all applicable requirements in the tariff, to reduce confusion and prevent ineligible projects from receiving the tariff rate.

In addition, I recommend that the Board limit the amount of tidal power allowed on the COMFIT rate, to limit the bill effects from tidal to those from small wind. (Regulations already limit he amount of small-wind capacity eligible for COMFIT). With my recommended tariffs, 3.5 MW of tidal generation would increase rates by about the same amount as 5 MW of small wind. With the Synapse tariffs, 2 MW of tidal generation would have the same effect as 5 MW of small wind. A 3.5 MW limit would allow for several demonstration tidal projects. Synapse assumes a 500 kW project size, and tidal turbines are often quite small, as the following examples suggest:

- Verdant's New York turbines are 35 kW, and its proposed turbines for Cornwall, Ontario would be 60–80 kW;
- Oceanflow Energy is currently developing 35-kW and 55-kW machines;
- Ocean Renewable Power Company's TGU turbine is 60 kW;[16]
- New Energy Corporation produces 5 kW to 25 kW Encurrent turbines, and is developing units up to 250 kW;
- Lucid Energy's PowerPipe turbines are currently produced in 5-kW increments;
- Marine Current Turbines has deployed 300-kW and 1.2-MW units;
- the OpenHydro turbine being tested in the Bay of Fundy is 1 MW.

Q: Does this conclude your testimony?

A: Yes.

[16] This appears to be the firm that Synapse refers to as Ocean Power Generation Systems or ORPG.