Draft COMFIT Tariffs: Initial Calculations and Discussion

Submitted by Synapse Energy Economics

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1. Introduction

This document is first deliverable from Synapse Energy Economics ("Synapse"), acting as consultant to the Nova Scotia Utility and Review Board ("Board"), in the process of developing Renewable Energy Community Based Feed-in Tariffs under the "Regulations Respecting Renewable Electricity made by the Governor in Council under Section 5 of Chapter 25 of the Acts of 2004, the *Electricity Act*" ("Regulations"). Part III, paragraph 20 of those Regulations directs the Board to set a tariff for five classes of generation facility: two size ranges of wind, combined heat and power (CHP) biomass, small-scale-in-stream tidal, and run-of-the-river hydroelectricity. Our effort is focused on developing proposals for those tariffs. There are, of course, myriad matters related to the design and implementation of the community feed-in tariffs that are, in our understanding, beyond our scope and role.

The material we are submitting today consists of this document and five Excel workbooks containing initial tariff calculations. This document describes our current thinking on a number of tariff design issues and presents the inputs to each tariff calculation. The tariff calculations presented here should be treated as a first draft. Inputs may change.

We have made five tariff calculations: one each for biomass CHP, small run-of-river hydro, in-stream tidal, wind projects up to 50 kW and wind projects above 50 kW. Due to the considerable uncertainty around the cost and operating characteristics of tidal projects, we have presented a range. We intend to work with stakeholders in the coming weeks to refine this calculation.

In terms of the timing, we are early in a process that is scheduled to run to April 2011. The Board has set a schedule going forward that provides additional opportunities for comment and iteration:

Information Requests to Synapse	Monday, January 10, 2011
Responses to Information Requests by Synapse	Monday, January 24, 2011
Second technical session with Intervenors	Monday, January 31, 2011
Final submissions by Intervenors to Synapse	Thursday, February 10, 2011
Final tariffs proposals by Synapse	Monday, February 28, 1011
Intervenor Evidence	Thursday, March 17, 2011
Hearing Commences	Monday, April 4, 2011

We appreciate the comments provided at, and subsequent to, the November 18, 2010 technical session. Those comments have informed our thinking and the draft tariffs presented here. Throughout this document we identify issues about which we are particularly interested in additional data from stakeholders. Note that well documented data is far more useful than unsupported opinion.

All model inputs are stated in 2009 Canadian dollars. Where source costs are in US dollars we assumed an exchange rate of 1:1. We make this assumption because making a small adjustment for currency conversion would imply a level of certainty and precision that is not there for most of the input assumptions.

2. Discussion of Key Issues

A. Automatic Adjustments in Tariffs

The Initial Submissions discussed three ways the COMFIT rates for a specific project could be adjusted over time. Certain cost components could be adjusted for inflation; for projects with fuel costs, these costs could be adjusted to track actual costs; and the cost of debt could be adjusted in response to changing interest rates. All three of these adjustments are part of the utility ratemakeing process.

Within our model, we have escalated fuel and O&M costs at the assumed general rate of inflation (1.92%). Thus, the energy cost derived using the model provides the target internal rate of return net of these escalating costs. There is a further question as to whether energy rate received by COMFIT projects should be flat or should be adjusted so that it rises over time to provide additional protection from inflation. Note that if the rate were adjusted to rise over time, it would be below the flat rate in the early years and above it in the later years. The net present value of the flat and increasing revenue streams would be the same.

At this point we believe that escalating fuel and O&M costs are best treated by including expected increases in the projection of annual costs that serves as the basis for the feed-in tariff. This provides appropriate recognition of those costs that are expected to be subject to inflation, and it is unnecessary to escalation some portion of the feed-in tariff. In other words, the tariffs proposed here are intended to be applied as a price that is flat (in nominal dollar terms) over time. We welcome additional input from the parties on this issue.

Regarding a fuel adjustment mechanism, first we note that adjusting COMFIT rates to reflect projects' actual fuel costs could impose significant administrative costs. In the case of utilities, one rate case affects a large portfolio of resources. Second, we note that companies treat biomass fuel costs as confidential, and this has made it very difficult to project prices – or even establish current prices – in other proceedings before the Board. A fuel adjustment mechanism would undoubtedly encounter the same difficulties. Thus, if we were to propose a mechanism to insulate biomass CHP projects from some of the risk associated with fuel costs, a superior approach might be to escalate these costs within the model by a factor designed to account for this risk. In the draft rates submitted today we have not included such a factor. We anticipate further discussion with stakeholders on the question of biomass fuel prices.

In the case of interest rates, our initial research with lenders suggests that COMFIT projects are more likely to be financed with longer term, fixed-rate loans than with adjustable rate loans or "mini-perm" loans that must be refinanced after a relatively short period. (See Section B below.) However, even if we determine that many lenders are likely to offer only adjustable rate loans to COMFIT projects, it seems preferable to account for this risk in our assumed cost of debt rather than in an adjustment mechanism. In the draft rates proposed here, we have included neither an interest rate adjustment mechanism nor a premium on the cost of debt to account for the risk of increased interest rates.

B. Capital Structure, Return on Equity and Debt Terms

The COMFIT program's focus on feed-in tariffs for small, community-owned projects presents several challenges when trying to develop assumptions about how projects will be financed. First, capital providers are unfamiliar with some of the technologies envisioned under the COMFIT (e.g. in-stream tidal), unaccustomed to evaluating projects with the ownership structures required by the COMFIT regulations, and less interested in projects of the scale envisioned under the COMFIT. This section discusses the initial financing assumptions entered into the model. Again, these assumptions are intended as a starting point for discussion and as benchmark values for stakeholder feedback and comment.

Initial return on equity (ROE) assumptions were benchmarked against current returns allowed for Nova Scotia utilities. Debt assumptions were drawn from stakeholder comments as well as from interviews with lenders active in Nova Scotia and other Canadian renewable energy markets.

Assumptions about capital structure were also drawn from stakeholder comments, from capital providers active in Canadian markets, and from our own experience. The minimum debt service coverage ratio (DSCR - cell F33 in the model) is also a driver for the capital structure. Lenders indicated that a minimum DSCR that would be needed to finance projects under the COMFIT. To the extent that modeled results were below the minimum DSCR, the amount of debt assumed in model was reduced, thus increasing the amount of assumed equity in the capital structure.

i. Capital Structure

We envision that all projects eligible for the COMFIT would have an equity component to their capital structure, as it seems unlikely that lenders would be willing to finance the full cost of a project. An exception to this rule may be projects developed by municipalities, who may be able to finance projects entirely with debt. For non-municipal projects, we assume that the equity percentage of capital structure will be driven by lenders. Our initial discussions with lenders suggest that a 60%/40% debt to equity ratio equity would be acceptable, although one lender suggested that up to 70%/30% debt to equity might be possible. However, some lenders also noted that they would not lend to emerging technologies such as tidal projects. Thus, our initial calculations conservatively assume a 60%/40% debt to equity ratio for all projects except tidal, for which we assume 100% equity.

In addition, the Regulations allow wind, hydro and tidal projects to be owned by partnerships as long as the majority owner is community based. Our initial calculations assume full ownership by a non-taxable community-based group. We will be investigating the implications of partnerships on project risks and capital structure and costs.

ii. Return on Equity

Conceptually, we propose to arrive at an allowed return on equity (ROE) for COMFIT projects by assessing the risks these projects face in excess of the risk that Nova Scotia Power Company's (NSPI's) stockholders face. NSPI is currently allowed a 9.35% ROE, and this is the figure the company uses for long term planning purposes.[1] Another important reference point is Heritage Gas Ltd.'s allowed ROE of 13%. In setting that company's initial ROE in 2003, the Board found that Heritage, a "greenfield utility" with very little existing infrastructure, faced significant risks above those faced by a "mature utility." Heritage argued that these risks justified an ROE of 14%. The Board allowed 13%.[2] The Board maintained this ROE for Heritage in a 2009 decision.[3]

COMFIT projects are likely to be riskier than NSPI projects for four reasons. First, there is project size risk, given that COMFIT projects are smaller than most utility projects. Equipment failure for a project consisting of one wind turbine, for example, is far more problematic than for a multiple turbine project. Second, there is portfolio risk. Investors who buy utility stocks rely on the utility's diversified portfolio of resources. Most entities owning COMFIT projects would own only one energy project, and many of them would own only one project of any type. Third, NSPI has the ability to petition the Board for rate increases, while COMFIT projects will not have this ability. And fourth, the inexperience and lack of internal expertise among community-based groups would increase risk for these groups relative to a utility project.

Potential investors are likely to see size and portfolio risk in all COMFIT projects. In thinking about the other two risk factors (no mechanism for rate adjustment and development risk) it is useful to consider the potential resources in three categories: biomass CHP projects, wind and hydro projects, and tidal projects. Biomass projects are unique in that they will be developed by corporations (we assume) and they will have fuel costs. Tidal projects are unique in that there is vastly more uncertainty about costs and performance than for the other technologies.

The companies developing biomass projects will have project management skills and resources, but they are unlikely to have built a biomass CHP project before. So there would still be development risk due to inexperience. Turning to fuel cost risk, if we determine that it is appropriate to account for this risk, we see the escalation of fuel costs within the model as the appropriate way to account for it – not a premium added to the ROE. Thus, we believe that the ROE should compensate biomass CHP projects for size risk, portfolio risk and development risk. As an initial estimate, we have used an 11.5% target ROE for biomass CHP projects – a risk premium of 215 basis points above NSPI's ROE. We will be seeking additional data on this issue in the coming weeks.

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[1] Nova Scotia Utility and Review Board (NSURB), *In the Matter of the Public Utilities Act and In the Matter of an Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to Rates, Charges and Regulations*, November 5, 2008. See also NSPI's *2009 IRP Update* at page 53.

[2] Nova Scotia Utility and Review Board (NSURB), *Decision In the Matter of the Gas Distribution Act and In the Matter of Franchise Applications for the Distribution of Natural gas in the Province of Nova Scotia*, 2003 NSUARB 8, February 7, 2003, pages 28-34.

[3] Nova Scotia Utility and Review Board (NSURB), *Decision In the Matter of the Gas Distribution Act and In the Matter ofHeritage Gas Ltd. For the Approval of Amendments to its Schedule of Rates, Tolls and Charges and Service Rules*, 2003 NSUARB 8, February 12, 2009.

Wind and hydro projects owned by community-based groups would not face fuel cost risk, but they would face project size risk, portfolio risk and substantial risks due to inexperience. In the case of a municipality with experience in public works projects, this last risk might be moderate. For a university with little experience in energy generation, this risk would be higher. In a true community-based effort, the risks posed by inexperience and would be extremely high. Power generation is not "mission critical" for any of these groups, and we believe that for all of them, an energy project would have to offer premium returns in order to attract capital from other projects. Our proposal includes a target ROE of 13% for wind and hydro projects owned by community groups a risk premium of 365 basis points over NSPI's ROE. Again, this is a very preliminary estimate, and as we move forward, it will be critical to talk to community-based groups that have developed, or are interested in developing, small energy projects.

In-stream tidal projects face tremendous uncertainty about project costs and operation. Estimates of installed costs vary by a factor of four. There is very little data from operating projects worldwide, so the reliability of operation and O&M costs are also highly uncertain. Operational problems are to be expected with a technology just emerging from the demonstration stage. If tidal developers put up their own equity, we believe they should receive a return above the NSPI rate for taking on these risks. If developers seek outside equity, they will probably have to show extremely high expected returns to attract capital. Our proposal is to include a 15% ROE for tidal projects.

iii. Terms of Debt

Our initial assumptions about the debt terms were obtained through stakeholder comments and from interviews with lenders that are currently active in, or plan to be active in, the Canadian and Nova Scotian renewable energy markets.

There was consensus among lenders that financing COMFIT projects will be challenging because of projects' small size, ownership structures, and the fact that some of the technologies are viewed as emerging. Project size may serve as a barrier to market entry for some lenders since the project's total capital requirements will likely below their minimum lending threshold. Manulife, for example, stated that they would likely not be involved with COMFIT projects since their threshold is $10 million and above.

The relationship between project size and ownership structure was also a point of uncertainty for the lenders. For those lenders that were interested in the market, there was a question as to whether COMFIT generation would be financed on a non-recourse project finance basis or with at least partial recourse to the project sponsor (e.g. the co-operative, the Community Economic Development Corporation, etc.).

Despite these uncertainties, some lenders and stakeholders were able to provide assumptions that have been entered into the model. National Leasing (a subsidiary of Canadian Western Bank), for example, stated that they are interested in the Nova Scotia market and would lend on a non-recourse basis to projects as small as $500,000. However, as project size and resulting capital costs decreased they would likely rely on recourse to the sponsor for security. Based on feedback from lenders such as National Leasing and others, the following inputs are included in the models.

- Interest rates. For non-recourse project finance, the creditworthiness of the off-taker (i.e. NSPI) is an important driver for determining the interest rate. A range of 6%-8% was suggested by stakeholders and lenders. As comparison, Ontario assumed 7.0% for all projects, whereas Vermont assumed 7.25%. We conservatively assume 8% for all projects (except tidal, which assumes 100% equity financing).

- Loan tenors. The loan tenor refers to the length of the loan that lenders are willing to provide. Lenders and stakeholders listed a range of potential tenors that ranged from 5-20 years. One lender expressing interest in the Nova Scotia COMFIT market stated that they would offer 10-15 year loans, assuming a 20-year COMFIT contract. We assume 15-year loans for all but small wind systems, for which we assume a 10-year loan. These assumed tenors are shorter than the duration of the COMFIT payments we assume (20 years).

- Debt Service Coverage Ratio (DSCR). The DSCR compares the cash available to the amount required to meet debt obligations. The minimum DSCR reported by lenders was 1.2x, however, they consistently stated that the projects contemplated under the COMFIT would require an average DSCR of at least 1.5x.

These assumptions for debt are submitted as preliminary and further research and stakeholder feedback is required. Two significant areas of uncertainty are:

- Construction finance. The debt terms above are based on input from lenders who would finance the project on a "take-out" basis – that is, they would put debt into the project after it had already been constructed, interconnected, and begun commercial operations. This is done because the lenders do not want to take development or construction risk on a project. Our assumptions are based on market experience with financing utility-scale projects and have not been informed by lenders who were able to provide concrete terms for how they would approach construction finance or how construction finance would alter their terms for projects the size of anticipated to participate in COMFIT.

- Small-scale projects. The assumptions above are based on projects that are $500,000 and over. For projects $500,000 and under (likely only to be wind < 50 kW), it is unclear whether these financing assumptions are reasonable. Lenders stated that as projects decreased below $500,000, there would need to be at least partial recourse to project sponsors and that interest rates would then be assessed against the specific sponsor. More research and stakeholder feedback is required to determine the structure and terms of financing for smaller-scale (i.e. < 50 kW) projects.

Table 1 summarizes our initial assumptions about capital structure and the cost of capital.

Table 1. Capital Structure and Cost of Capital in Initial Rate Calculations

Entity	Debt/Equity	Cost of Debt	Return on Equity	WACC (pre-tax)
NSPI	62.5/37.5	7.7%	9.35%	8.33%
Biomass CHP	60/40	8.0%	11.50%	9.40%
Wind and Hydro	60/40	8.0%	13.00%	10.00%
In-Stream Tidal	100% equity	N/A	15.00%	15.00%

We assume 100% corporate ownership of biomass CHP projects. For wind, hydro and tidal, our initial calculations are for projects fully owned by non-taxable community-owned groups. We are researching how the cost of capital might differ for a community/private-sector partnership.

C. Tariff Differentiation

The initial submissions included recommendations to differentiate tariffs based on a number of factors, including:

- Project ownership,
- Project size,
- Energy conversion technologies within a resource category,
- Location within the province, and
- Time of energy production.

The Regulations are silent about tariff differentiation beyond that required for wind projects. Section 20(1) of the Regulations directs the Board to “set a tariff under this Section for” wind with a capacity of 50 kW or less; wind with a capacity over 50 kW; a combined heat and power biomass facility; small-scale-in-stream tidal; and run-of-river hydroelectricity. The Regulations do not direct the Board to set “one or more” tariffs for these five resources. Further, the fact that the Regulations do provide for two wind tariffs suggests that the Regulations are intended to be prescriptive in terms of tariff differentiation.

There are several consequences to setting only these five tariffs for these resources. First, data we have seen indicate that the cost per kW of wind projects between 50 kW and about 2 MW vary widely, with the larger projects being considerably cheaper than the smaller ones. Basing this tariff on the cost of a smaller project would provide profits to large projects well in excess of the target rate of return. Basing the tariff on the cost of a large project could effectively shut the door to smaller projects. Granted, all of the technologies are likely to exhibit economies of scale, and short of establishing a very large number of tariffs, tradeoffs will have to be made. However, this problem appears to be particularly vexing in the case of wind projects over 50 kW.

Second, the Regulations allow wind, hydro and tidal projects to be owned fully by community-based groups or by partnerships where the majority owner is such a group. Presumably, a community-based group would seek a partner with financial resources and/or project development experience. A project launched by such a partnership could have significantly lower risks and costs than one launched by a single community-based group, and the same problem of excess profits versus lost opportunities would arise.

Third, there are several different commercial biomass CHP technologies, including the combustion of cellulosic biomass in a boiler, combustion of gasified cellulosic biomass, and combustion of anaerobic digester gases (ADG). Notably, stakeholders have expressed interest in the COMFIT for all three types of project. However, electricity from a boiler-based project is will typically be less expensive than energy from the other two technologies, and setting the biomass CHP tariff based on a boiler-based project could exclude the other technologies from the COMFIT.

D. Interconnection

There are essentially two ways the cost of interconnecting distributed generation can be recovered. First, the costs can be socialized by putting them in the utility's ratebase. Second, they can be borne by project developers. In Nova Scotia, interconnection costs are paid by project developers, so we must determine the best way to include interconnection costs in the COMFIT rate.

NSPI has separate interconnection processes for generation projects under 100 kW and over 100 kW. For projects up to 100 kW, there is no application fee and the interconnection is treated in a manner similar to a service connection. However, generators in this size range are responsible for the cost of any additions or system upgrades necessary to interconnect the generator (for example, a three-phase generator seeking to connect in an area of one-phase distribution service).

For projects over 100 kW in size, it is useful to consider interconnection costs in the following four categories:

- Required studies,
- Customer's interconnection facilities
- NSPI interconnection facilities, and
- Distribution system upgrades.

The NSPI interconnection facilities are required to deliver power from the generator to the distribution system, and include the NSPI equipment located at the generation site as well as the line extension from the site to the existing distribution system. These facilities are supplied and installed by NSPI and are funded by the project developer. The customer's interconnection facilities (cables, switches, etc) connect the generator to the NSPI interconnection facilities and are required to be provided by the project developer.

Distribution system upgrades are required when the distribution system must be modified in order to accommodate the generator. The most common upgrade is required when a three-phase generator seeks to connect in an area of one-phase distribution service. In this case, sections of the distribution system must be upgraded to three-phase. Other upgrades cases include increasing conductor size, system voltage conversions and equipment relocations.

Two studies are required for interconnection of units over 100 kW: a Preliminary Review and a Combined System Impact and Facilities Study (SIS). The developer is charged a flat rate of $1,000 for the Preliminary Review. The cost of the SIS depends on the proposed generator and location, and it ranges between about $5,000 and $10,000, with most studies costing less than $7,500.

The cost of the generator tie-in line extension depends heavily on the distance between the generator and distribution system. NSPI's Preliminary Review estimate for three-phase line extensions is $55,000 per kilometer. Actual costs are affected by line routing, terrain and soil conditions. Costs of the required NSPI interconnection facilities at the generator site are typically in the range of $85,000 and there is much less variation in this cost (across different projects) than in the tie-in line extension and potential system upgrade costs.

The cost of required system upgrades can vary widely across projects. In many cases no upgrades are required. In cases where upgrades are required, these costs may be significant relative to the total costs of a generation project, and particularly so for small generators.

Numerous generation projects >100 kW have been assessed for connection to the distribution system in Nova Scotia and the average cost estimate for interconnection of these projects has been approximately $250,000, with estimates ranging from $85,000 to $500,000. For those projects that have proceeded to construction, the average interconnection cost was approximately $180,000 (2005-2010 dollars).

Conceptually, we propose to include in our calculations an amount of interconnection funds sufficient for a project that: a) is reasonably close to the distribution system and b) requires minimal or no system upgrades. We hope that by reducing the range of these two variables we can establish COMFIT rates that allow many projects to move forward while not providing windfalls to projects with very low interconnection costs.

Our initial calculations include interconnection costs of $110,000 for biomass CHP projects, $20,000 for small wind projects and $210,000 for all other projects. We assume that biomass projects are at facilities currently connected to NSPI's distribution system, so a line extension would not be needed. We estimate the average cost of required NSPI facilities other than a line extension to be $10,000. We also assume that small wind projects are at the distribution system and no line extension is needed. For wind, hydro and tidal projects, the line extension is priced based on a length of 2 km. Table 2 shows the components of these initial cost estimates.

Table 2. Components of Draft Interconnection Costs

Component	Biomass CHP	Wind ≤50 kW	Wind >50 kW, Hydro, Tidal
Studies	$10,000	$0	$10,000
NSPI facilities	$10,000	$10,000	$110,000
Customer facilities	$90,000	$10,000	$90,000
System Upgrades	$0	$0	$0
Total	$110,000	$20,000	$210,000

Refining these interconnection costs will be a key piece of our work between now and April, and there will be two important issues in this work. First, this approach would make it more difficult for projects located far from the distribution system to cover their costs. Within a resource class, this seems reasonable. Why not develop the resources closest to the grid first? However, it will be important to base the gen tie cost assumption on a reasonable distance from the grid. We will be reviewing data on the location of renewable resources in Nova Scotia, and we welcome relevant information from stakeholders. In addition, the average distance from the grid may differ across resource classes. Viable wind resources, for example, may be farther from the grid than the viable hydro resources. In that case it would be important to include different gen-tie costs for different resources.

Second, we must assume that not allocating funds for system upgrades in our model will effectively close the door to projects that necessitate costly system upgrades. It will be important to determine the impact this is likely to have on the COMFIT program before finalizing this decision. How frequently will system upgrades be needed to accommodate distributed generation, and what is the nature and cost of those upgrades? We welcome information on these questions.

F. Other Assumptions

Other input assumptions in our initial calculations are as follows. More research is needed on virtually all of these assumptions, and we welcome data from stakeholders. Resource-specific assumptions are described in Section 3. As discussed below, our exclusion of any grants or tax incentives for COMFIT projects (except biomass CHP) has the largest impact on results of these assumptions.

<u>General inflation (cell B3)</u>. We assume a rate of 1.92%, taken from NSPI's *2009 IRP Update*.

<u>Preconstruction development costs (cell B5)</u>. This cost category includes all design and preconstruction analysis costs, including studies required by the federal or provincial governments. In a number of cases it was not clear whether installed cost data we reviewed include these costs. Thus, in some of the 12-20-10 models this cost is broken out and in others it is not. We welcome input from stakeholders on preconstruction development costs.

<u>Up-front maintenance reserves (cell B9)</u>. This is a maintenance escrow account that is often required by lenders. More research is needed to determine whether this will be required and how to size it. In our initial calculations, we include it and size it as half of year-one O&M costs.

<u>Working capital reserve (cell B10).</u> This is another cash reserve often required by lenders. In our initial calculations, the working capital reserve is sized as half of total year-one expenses.

<u>Debt Service reserve (cell B11)</u>. Another reserve account often required by lenders. In our initial calculations, the debt service reserve is sized as half of year-one debt service cost.

<u>Interest during construction (cell B14)</u>. We calculate this as: (Construction loan value) × (50%) × (interest rate). We assume that the loan value is equal to the Equipment and Installation costs plus Interconnection costs. We assume an 8% interest rate.

Grants and tax incentives (cell B23 and Tax Depreciation worksheet). Based on comments from stakeholders and our own research, we have not included any grants in calculating the COMFIT rates. It appears that we cannot assume that any grants will be available to all COMFIT projects. We also assume that wind, hydro and tidal projects are fully owned by non-taxable entities and thus that these projects cannot benefit from provisions for accelerated depreciation. We do assume that biomass CHP projects benefit from accelerated depreciation. In comparing our proposed rates with FIT rates in other jurisdictions, the assumption of no grants or tax benefits is critical. For example, our draft rates for wind and hydro are considerably higher than Vermont's FIT rates, however the rates in Vermont assume a 30% investment tax credit and accelerated depreciation.

Fees and closing costs (cells B39-41). We assume lenders charge an up-front fee equal to one percent of the loan value, and that closing costs (including legal and other consulting fees).

Depreciation (cells B44-48). These draft rates assume wind, hydro and tidal projects are fully owned by non-taxable, community-based groups. In future drafts this assumption may change. For biomass CHP projects, we assume that 85% of the equipment is eligible for Class 43.1 accelerated depreciation (30% declining balance rate), 10% is depreciated on a straight line basis and 5% is non depreciable. This is a placeholder assumption, and more research is needed to determine the required depreciation treatment of this equipment. We are also looking into which projects would be eligible for an initial capital cost allowance (CCA).

Insurance (cell F15). We estimate annual insurance costs to be 4% of hard costs (Equipment and Installation plus Interconnection), based on data from the Vermont FIT proceeding. More work is needed to refine this assumption.

Property tax rate (cell F23). Commercial property taxes vary widely across Nova Scotia – from about 1.5% to 5.5%.[4] This presents a challenge, because property taxes have a significant impact on a project's rate of return. Our initial calculations assume a rate of 3.5%. We will be seeking ways to reduce the range of error associated with this input. The tax rate is multiplied by the assessed value of the project (cell F20). The initial assessed value is calculated as total equipment costs, including interconnection. The model includes a modifying factor (cell F19) that allows the user to reduce the initial assessed value to a percentage of these total costs. Further, we assume that the assessed value falls by 4% per year to a floor of 20% of the initial value (cells F21-22). This is intended to simulate a declining value based on periodic reassessments of the plant.

Income tax rates (Cells F36-37). We assume a federal income tax rate of 18% and a provincial rate of 16%. We further assume that no portion of provincial taxes paid is deductable from federal taxes. In our initial calculations, only biomass CHP projects are subject to income taxes. In the future, we will investigate the tax implications of partnerships between community-based and private sector groups and determine whether separate tariffs are needed for these projects.

[4] A list of property tax rates in the Province can be found at: http://www.gov.ns.ca/snsmr/muns/fin/tax/.

Duration of COMFIT payments. Although not included as an input to the model, we assume that COMFIT payments would be made to approved projects for 20 years.

3. Initial Calculations of Rates

This section describes our initial calculation of COMFIT rates and the key input assumptions used. These rates are a first draft, submitted roughly one month into a process to develop tariff proposals. Synapse will submit final tariff proposals at the end of February, 2011. Table 3 summarizes our initial rate calculations.

Table 3. Summary of Initial Rate Calculations

	Wind ≤50 kW	Wind >50 kW	Biomass CHP	Hydro	Tidal
Rate ($/MWh)	$655	$158	$72	$197	$780

A. Wind Projects Up to 50 kW

Our initial calculation indicates that an energy rate of $655 per MWh would be needed for small wind projects to achieve an internal rate of return of 13.0%. Key assumptions behind this calculation are as follows.

- We assume a capacity of 25 kW.
- We have reduced the debt/equity ratio for small wind projects to 56%/44% in order to achieve an average DSCR of 1.5x.
- Based on conversations with lenders, we have assumed a debt term of 10 years for small wind projects. For all other projects, we assume 15-year loans.
- The project benefits from no grants or tax incentives.
- The rate cited above ($655 per MWh) is for projects located at the distribution system. That is, that interconnection costs do not include the cost of a line extension. Including the cost of a 2 km line extension would increase the resulting energy rate to $845 per MWh.
- See Section 2B for a discussion of other assumptions regarding capital structure and the cost of capital.

i. Inputs

Table 4 below shows the key assumptions in the 12-20-10 version of the small wind model and the sources of those assumptions. Assumptions about costs and operating parameters come from discussions with developers of small wind projects in Canada and the U.S. and other knowledgeable individuals.

Table 4. Small Wind Input Assumptions

Assumption	Value	Source
Ownership	Fully owned by a community-based group	Synapse
Debt/equity ratio	55/45	Discussions with lenders
Cost of debt	8.0%	Discussions with lenders
Loan life (years)	10	Discussions with lenders
Target rate of return	13%	Synapse
Capacity (MW)	0.5	Synapse
Capacity factor (%)	20%	Synapse
Annual generation (MWh)	88	Synapse
Equipment and installation cost ($)	$250,000	Synapse
Interconnection cost ($)	$20,000	Synapse (at grid)
Total project costs* ($)	$453,313	Synapse
O&M cost ($/yr)	$4,980	Synapse
Major maintenance ($, year)	none	N/A
Federal income tax rate (%)	N/A	N/A
Provincial income tax rate (%)	N/A	N/A
Property tax rate (%)	3.5%	Synapse

**Total project costs include: equipment and installation; interconnection; development costs; reserve accounts, closing costs and fees, and interest during construction.*

ii. Discussion

Based on the information received, wind projects in this size range can expect to have a net capacity factor between approximately 20% and 30%, depending on the size of the project. Since this scenario assumes an installation on the low end of the size range, we are assuming a 20% net capacity factor. This assumption has a significant impact on the calculated energy rate.

B. Wind Projects Over 50 kW

Our initial calculation indicates that an energy rate of $158 per MWh would be needed for wind projects over 50 kW to achieve an internal rate of return of 13.0%. Key assumptions behind this calculation are as follows.

- We assume a capacity of 1.5MW.
- The project benefits from no grants or tax incentives.
- Interconnection costs assume a distance of 2 km from the grid.
- See Section 2B for a discussion of assumptions regarding capital structure and the cost of capital.

i. Inputs

Table 5 below shows the key assumptions in the 12-20-10 version of the large wind model and the sources of those assumptions. Assumptions about costs and operating parameters come from discussions with developers of wind projects in Canada and the U.S. and other knowledgeable individuals.

Table 5. Large Wind Input Assumptions

Assumption	Value	Source
Ownership	Fully owned by a community-based group	Synapse
Debt/equity ratio	60/40	Discussions with lenders
Cost of debt	8.0%	Discussions with lenders
Loan life (years)	15	Discussions with lenders
Target rate of return	13%	Synapse
Capacity (MW)	1.5	Synapse
Capacity factor (%)	30%	Synapse
Annual generation (MWh)	3,942	Synapse
Equipment and installation cost ($)	$2,675,000	Synapse
Interconnection cost ($)	$210,000	Synapse (2-km from grid)
Total project costs ($)	$3,840,840	Synapse
O&M cost ($/yr)	$55,000	Synapse
Major maintenance ($, year)	Included in O&M	N/A
Federal income tax rate (%)	N/A	N/A
Provincial income tax rate (%)	N/A	N/A
Property tax rate (%)	3.5%	Synapse

**Total project costs include: equipment and installation; interconnection; development costs; reserve accounts, closing costs and fees, and interest during construction.*

C. Biomass CHP

Our initial calculation indicates that an energy rate of $72 per MWh would be needed for biomass projects to achieve an after-tax internal rate of return of 11.50%. Key assumptions behind this calculation are as follows.

- We have only included the cost of the electric equipment at the CHP plant in this calculation. Since the host facility benefits from the steam produced, and not electric ratepayers, we do not include these costs in the COMFIT rate.
- The cost and operating input assumptions used are based on a 35 mmBtu/hr stoker boiler and a 0.5 MW back-pressure turbine. We anticipate working with stakeholders to change or refine this assumption in the coming months.
- We have included fuel costs in the calculation.
- See Section 2B for a discussion of other assumptions regarding capital structure and the cost of capital.

i. Inputs

Table 6 below shows the key assumptions in the 12-20-10 version of the biomass CHP model and the sources of those assumptions. Again, note that all costs represent the cost of electric equipment only. This includes the steam turbine and related equipment, interconnection costs, and a prorated portion of project development costs. The cost of the fuel yard, fuel handling equipment and the boiler and related equipment are not included. The cost and performance assumptions are based on *Biomass Combined Heat and Power*, a report produced by the US EPA, and on discussions with knowledgeable individuals in the U.S. and Nova Scotia.[5]

Table 6. Biomass CHP Input Assumptions

Assumption	Value	Source
Ownership	100% corporate	Synapse
Debt/equity ratio	60/40	Research with lenders
Cost of debt	8.0%	Research with lenders
Loan life (years)	15	Research with lenders
Target rate of return	11.50%	Synapse
Capacity (MW)	0.5	EPA 2007
Capacity factor (%)	90%	EPA 2007
Annual generation (MWh)	3,942	EPA 2007
Equipment and installation cost ($)	$1,001,990	EPA 2007 and Synapse
Interconnection cost ($)	$110,000	Synapse (at grid)
Total project costs* ($)	$2,007,821	Calculated
O&M cost ($/yr)	$15,768	Synapse
Major maintenance ($, year)	$10,000, year 10	Synapse
Federal income tax rate (%)	18%	Canada Revenue Agency
Provincial income tax rate (%)	16%	Canada Revenue Agency
Property tax rate (%)	3.5%	Synapse

**Total project costs include: equipment and installation; interconnection; development costs; reserve accounts, closing costs and fees, and interest during construction.*

Table 7 shows additional cost and operating assumptions used in the 12-20-10 version of the biomass CHP model.

[5] US EPA, *Biomass Combined Heat and Power Catalog of Technologies*, September 2007. All cost data from the EPA document have been converted from 2006 dollars to 2009.

Table 7. Additional Biomass CHP Assumptions

Assumption	Value	Source
Boiler fuel use (mmBtu/hr)	35.4	EPA 2007
Annual fuel use (mmBtu)	279,076	EPA 2007
Boiler capacity factor (%)	90%	EPA 2007
Annual operation (hrs)	7,883	EPA 2007
Fuel cost ($/mmBtu)	$3.50	Synapse
Total fuel cost ($/yr)	$976,765	Calculated
Turbine cost ($)	$450,500	EPA 2007
Balance of electric plant ($)	$360,400	Synapse
Development costs ($)	$178,400	Synapse
Installation ($)	$81,090	Synapse
Electric plant O&M ($/MWh)	$4.00	EPA 2007
Process steam rate (mmBtu/hr)	20.6	EPA 2007
Annual process steam out (mmBtu)	162,400	Calculated
Annual electricity out (mmBtu)	13,450	EPA 2007
Total energy out (mmBtu)	175,850	EPA 2007
Steam % of output	92%	Calculated
Electricity % of output	8%	Calculated
Losses (mmBtu)	103,226	Calculated
Input to steam (mmBtu)	257,730	Calculated
Input to electric (mmBtu)	21,345	Calculated
Electric heat rate (Btu/kWh)	5,415	Calculated
Annual fuel cost to steam ($)	$902,056	Calculated
Annual fuel cost to electric ($)	$74,709	Calculated

ii. Discussion

Several issues about the data from the EPA 2007 report are worth noting. First, we have not yet compared these costs with current data from equipment vendors, and as we do, these numbers may change. Second, both the boiler and turbine capacity factors in the report (90%) seem too high. We expect that we will revise these numbers as well, but we have presented them here as reported in the EPA study for comment.

Preconstruction development costs are assumed to be 20% of equipment and installation costs. EPA 2007 estimates turbine O&M at $4.00 per MWh. We use this figure for routine O&M and include $10,000 for a turbine overhaul in year 10. We assume a twenty-year turbine lifetime.

We have allocated total fuel costs to the generation of electricity by apportioning energy losses to the steam and electricity sides using the ratio of steam to electricity produced. There is a legitimate question as to whether fuel costs should be included in the calculation at all. A facility likely to develop a biomass CHP plant for the COMFIT is likely to be producing wood wastes today that they would use to fuel the CHP plant. Currently, this facility would be selling this waste to existing biomass-fueled projects. When the COMFIT CHP project began operation, the facility’s actual fuel cost would be zero (assuming it had sized the project such that it did not have to buy more fuel). The facility’s opportunity cost of fuel would be equal to the rate at which they were selling fuel prior to construction. The question is, should this opportunity cost be included as the fuel cost, or should the fuel cost be zero.

Our current thinking is that, the economic analysis of a CHP project (such as the one companies would use to decide whether to build a CHP plant) would properly include the opportunity cost of the fuel. Thus, if we want to produce a COMFIT rate that produces new biomass CHP plants, we need to include this cost as well. We invite comment on this proposed treatment of biomass fuel costs.

As noted, determining the market price of biomass has been challenging in previous cases before the Board. One thing we know is that transportation is a significant portion of the delivered cost of biomass. Thus, the price that a company is being paid for its waste wood, will be significantly lower than the delivered cost of this fuel. Based anecdotal evidence, our initial estimate of the delivered cost of biomass in the province is about \$5.25 per mmBtu, and we estimate the “non-delivered” price to be \$3.50 per mmBtu. We use the latter price as a COMFIT CHP plant’s cost of fuel. We welcome data on biomass fuel prices.

D. Run-of-River Hydro

Our initial calculation indicates that an energy rate of \$197 per MWh would be needed for run-of-river hydro projects to achieve an internal rate of return of 13.0%. Key assumptions behind this calculation are as follows.

- A 1.2 MW project is assumed with a net capacity factor of 45%.
- The project benefits from no grants or tax incentives.
- We assume that hydro projects have a useful life greater than 20 years, and thus we include a residual value for small hydro projects equal to the remaining book value of the plant after 20 years (cell F45 in the hydro model). (All other projects are assumed to have a 20-year life.)
- Interconnection costs are based on a distance of 2 km from the grid.
- See Section 2B for a discussion of assumptions regarding capital structure and the cost of capital.

i. Inputs

Table 8 below shows the key assumptions in the 12-20-10 version of the hydro model and the sources of those assumptions. The majority of the assumptions for the hydro rate are based on data provided in the Vermont FIT process, as this is the most robust and widely vetted data we have found to date. More work is needed to determine exactly what costs were included in the capital and O&M cost figures in Vermont and to ensure that we are capturing all components of project costs.

Table 8. Small Hydro Input Assumptions

Assumption	Value	Source
Ownership	Fully owned by a community-based group	Synapse
Debt/equity ratio	60/40	Synapse
Cost of debt	8.0%	Synapse
Loan life (years)	15	Synapse
Target rate of return	13%	Synapse
Capacity (MW)	1.28	VT FIT for small hydro
Capacity factor (%)	45%	VT FIT for small hydro
Annual generation (MWh)	5,035	Calculated
Equipment and installation cost ($)	$5,341,440	VT FIT for small hydro
Interconnection cost ($)	$210,000	Synapse (2-km from grid)
Total project costs* ($)	$5,808,684	NS Power
O&M cost ($/yr)	$ 129,078	VT FIT for small hydro
Major maintenance ($, year)	none	VT FIT for small hydro
Federal income tax rate (%)	N/A	N/A
Provincial income tax rate (%)	N/A	N/A
Property tax rate (%)	3.5%	Synapse

**Total project costs include: equipment and installation; interconnection; development costs; reserve accounts, closing costs and fees, and interest during construction.*

E. In-Stream Tidal

In-stream tidal technology is not currently commercial, and we found a very wide range of assumptions regarding cost and performance. Using data based roughly on the midpoints of the ranges we found, our initial calculations suggest that a rate of $780 per MWh would be needed to provide an internal rate of return of 15.0%. Key assumptions behind this calculation are as follows.

- We modeled a 0.5 MW project with a net capacity factor of 40%.
- The project is financed with 100% equity.
- The project benefits from no grants or tax incentives.
- We have not included interconnection costs, as most of our sources included these costs in total installed cost and did not provide a breakout of total installed costs.
- In addition to the inputs discussed below, we also looked at a high- and low-cost scenarios for tidal. The high-cost scenario assumed total project costs of $15,733 per kW and total O&M expenses of $220,000 per year and required an energy rate of $986 per MWh to achieve the target rate of return. The low-cost scenario assumed total project costs of $10,255 per kW and total O&M expenses of $30,000 per year and required an energy rate of $576 per MWh.

i. Inputs

Table 9 below shows the key assumptions in the 12-20-10 version of the mid-cost tidal model and the sources of those assumptions.

Table 9. Mid-Cost Tidal Input Assumptions

Assumption	Value	Source
Ownership	Fully owned by a community-based group	Synapse
Debt/equity ratio	60/40	Synapse
Cost of debt	8.0%	Synapse
Loan life (years)	15	Synapse
Target rate of return	15%	Synapse
Capacity (MW)	0.5	Synapse
Capacity factor (%)	40%	Synapse
Annual generation (MWh)	1,752	Calculated
Equipment and installation cost ($)	$6,250,000	Synapse
Interconnection cost ($)	Included in Equip. & Install.	Synapse
Total project costs* ($)	$6,496,875	Synapse
O&M cost ($/yr)	$ 125,000	Synapse
Major maintenance ($, year)	Included in O&M	Synapse
Federal income tax rate (%)	N/A	N/A
Provincial income tax rate (%)	N/A	N/A
Property tax rate (%)	3.5%	Synapse

**Total project costs include: equipment and installation; interconnection; development costs; reserve accounts, closing costs and fees, and interest during construction.*

ii. Discussion

Our capacity factor assumption is based primarily on an Electric Power Research Institute (EPRI) report published in 2006, which investigated the tidal resource potential across Nova Scotia.[6]

As indicated in Table 10 below, capital cost estimates we found range from a low of $3,900 at a recently proposed tidal project in Maine[7] to as much as $17,000/kW for pre-demonstration projects as estimated in a recent study by Ernst & Young and Black & Veatch (EY&BV study).[8] It is not clear what cost components are included in the low estimate, and the cost of interconnection is not likely to be included. The capital cost estimates in the EY&BV study represent all-in capital costs including construction costs (e.g., overnight capital cost, owner's costs and interest during construction),

[6] EPRI 2006. North America Tidal In-Stream Energy Conversion Technology Feasibility Study, available at http://oceanenergy.epri.com/attachments/streamenergy/reports/008_Summary_Tidal_Report_06-10-06.pdf

[7] Half-Moon Cove tidal project, http://www.mainetidalpower.com/economics.html

[8] Ernst &Young and Black & Veatch 2010. Cost of and Financial Support for Wave, Tidal Stream and Tidal Range Generation in the UK: A report for the Department of Energy and Climate Change and the Scottish Government. In the study, pre-demonstration refers to the first stage of project development before demonstration stake projects have been installed. Demonstration refers to a stage of development assumed to be reached when a developer installs their first 10 MW project.

interconnection costs, and pre-development costs (e.g., pre-licensing, public enquiry and planning, technical development).

Operation and maintenance (O&M) costs range from a low of $28 per kW-yr for Maine's tidal project to $723 per kW-yr from the EY&BV study. The O&M in the BY&BV study includes variable and fixed O&M costs, grid use of service costs, insurance costs, and decommissioning fund costs.

Table 10. Summary of In-Stream Tidal Cost Survey

Project/Study	Location	Status	Size	Total cost	Capital Cost	O&M cost
E&Y and B&V report	UK and Scotland	n/a	n/a	n/a	Pre-demonstration: $17,141/kW Demonstration: $6,573/kW	Pre-demonstration: $723/kW-yr Demonstration: $475/kW
Canoe Pass	British Columbia, Canada	expected to be installed in the second half of 2010.	500 kW	$6.5 million	$13,000/kW	n/a
Fundy Ocean Research Centre for Energy (FORCE)	Nova Scotia, Canada	deployed November 12, 2009	1 MW	$14.6 million	$14,600/kW	n/a
5MW Kyle Rhea schem	Scotland	scheduled for 2013	5 MW	£35million ($55 million)	$11000/kW	n/a
Half-Moon Cove	Maine, US	FERC preliminary permit on Dec 3, 2010	9 - 16 MW	$35 to $80 million	$3,900 - $6,000/kW	$28-$47/kW-yr or $7-$10/MWh
NS Tidal Power Stakeholders	Nova Scotia, Canada	n/a	small scale	n/a	$10,000/kW	$300-$500/kW-yr