

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE ELECTRICITY ACT

- and -

IN THE MATTER OF a hearing to determine Renewable Energy Community Based Feed-in
Tariffs

Direct Testimony and Exhibits of

Bruce Biewald, Wilson Rickerson, Geoff Keith and Ms. Susan Shaw, P. Eng.

On behalf of Board Counsel

March 2, 2011

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INTRODUCTION**Q. PLEASE STATE THE NAMES, POSITIONS AND BUSINESS ADDRESSES OF EACH PERSON SPONSORING THIS EVIDENCE.**

A. Bruce Biewald is the President of Synapse Energy Economics, a consulting firm located at 22 Pearl St., Cambridge, Massachusetts 02139. Wilson Rickerson is the Chief Executive Officer of Meister Consultants Group, located at 98 North Washington Street, Boston, Massachusetts 02114. Geoff Keith is an Associate at Synapse Energy Economics, also working at the Cambridge office. Ms. Susan Shaw P. Eng., is an independent consultant with expertise in combined heat and power, district heating and renewable energy. Her business address is 421 Baker Street, London, Ontario N6C 1X8.

Q. PLEASE DESCRIBE THE EDUCATIONAL AND PROFESSIONAL BACKGROUNDS OF THE PEOPLE SPONSORING THIS EVIDENCE.

A. Our educational and professional backgrounds are detailed in Exhibit A of this evidence.

Q. PLEASE DESCRIBE THE WORK EACH OF YOU DID IN THE DEVELOPMENT OF THE TARIFF RATES PROPOSED HERE.

A. Mr. Biewald oversaw the effort, reviewed stakeholder comments and discussed research with project team members, helped develop the spreadsheet model and drafted sections of materials distributed to stakeholders and of this evidence. Mr. Rickerson led the research on the cost and terms of debt, project ownership, the appropriate return on equity and on the cost of wind projects. He also provided information on the design of feed-in tariffs (FITs) and the rates established in other jurisdictions. Mr. Keith led the research on the cost of hydro and tidal projects, the cost of interconnection and issues related to taxes and depreciation. He also helped develop the spreadsheet model and worked with Ms. Shaw to develop the proposed biomass combined heat and power (CHP) tariff. Ms. Shaw provided the assumptions about the type of equipment on which to base the biomass CHP tariff and the cost and operation of that equipment.

Q. HAVE ANY OF YOU FILED EVIDENCE PREVIOUSLY BEFORE THE BOARD?

A. Mr. Biewald has. His work for the Board staff in the last few years includes consulting on NSPI's integrated resource plan, demand side management, and the Tufts Cove waste heat recovery project. He has prepared reports and evidence on these matters.

Q. IN ADDITION TO YOURSELVES, WERE THERE OTHER PEOPLE ON YOUR CONSULTING TEAM FOR THIS PROJECT?

A. Yes. Matthew Karcher, then Principal of Deacon Harbor Financial and now at Wells Fargo, helped revise the cash flow model developed in the Vermont FIT proceeding for use in this proceeding. Hilary Flynn, Director of International Business at Meister Consultants Group, helped with the research on project ownership and the cost of debt and equity. While these individuals contributed to the research for this project, the evidence provided here is our own.

Q. WHAT IS THE PURPOSE OF THE EVIDENCE YOU ARE PROVIDING?

A. The purpose of this evidence is to propose tariffs for Nova Scotia's Community-Based Feed-In Tariff (COMFIT) program and to describe the rationale, assumptions and calculations behind the proposed tariffs.

Q. HOW IS YOUR EVIDENCE ORGANIZED?

A. This evidence is organized as follows.

- A. Introduction
- B. Overview and general Issues
- C. Project ownership
- D. The terms and cost of debt
- E. Capital structure and the cost of equity
- F. Taxes and depreciation
- G. The cost of interconnection
- H. Other input assumptions
- I. The proposed tariff for wind ≤ 50 kW
- J. The proposed tariff for wind > 50 kW
- K. The proposed tariff for biomass CHP
- L. The proposed tariff for run-of-river hydro
- M. The proposed tariff for small, in-stream tidal

Q. HAVE YOU FILED EXHIBITS WITH YOUR EVIDENCE?

A. Yes, we have filed the following exhibits with this evidence.

- A. Background and qualifications of the sponsors
- B. The effect of income tax status on COMFIT rates

- C. Assumptions about capital structure and costs in the tariff modeling
- D. Interconnection information provided by NSPI
- E. Interconnection costs included in the tariff modeling
- F. Cost and performance assumptions in the tariff modeling
- G. Information requested from sawmills
- H. The effect of steam demand on the CHP rate

B. OVERVIEW AND GENERAL ISSUES

Q. WHAT TARIFF RATES ARE YOU PROPOSING?

A. We are proposing the following tariff rates.

- \$452 per MWh for wind projects ≤50 kW,
- \$139 per MWh for wind projects >50 kW,
- \$156 per MWh in year 2012 for biomass CHP projects, composed of a fixed component of \$94 per MWh and an escalating component of \$62 per MWh representing the cost of fuel;
- \$140 per MWh for run-of-river hydro projects, and
- \$652 per MWh for in-stream tidal projects.

These rates are stated in 2012 Canadian dollars, as we believe that this is the earliest year in which projects are likely to be developed. Source data stated in 2010 or 2011 dollars have been adjusted using the assumed annual rate of inflation in our costing model, 1.92%. Source data stated in dollar years prior to 2010 have been adjusted to 2010 using the appropriate GDP implicit price deflator (i.e., from either Canada or the U.S.) and then adjusted to 2012 dollars using the inflation rate in the model.

Q. ARE YOU PROPOSING FLAT COMFIT RATES OR RATES THAT ESCALATE OVER TIME?

A. With the exception of the biomass CHP tariff, we are proposing flat rates. We understand that some jurisdictions have chosen to escalate some portion of their feed-in tariff rates over time to account for costs to projects that are expected to increase with inflation. However, in the case of power plants using renewable fuels, operating expenses – which would be subject to inflation – tend to make up a relatively small portion of total costs. In light of this, we examined the portion of each tariff rate attributable to operating costs to determine whether we felt it was important to propose

escalating COMFIT rates. We found that operating costs (not including fuel costs for biomass) as a percentage of total costs are approximately 10% for the types of projects considered here. If an escalating approach were to be used for this portion of the project costs, then compared to the level rate the starting point would be a bit lower and the ending point a bit higher, such that the "cumulative present value" over the full period would be the same. This would be only a slight modification to the level tariff structure, and would add some complexity in terms of the timing and administration of adjustments. In our judgment a straightforward approach in which the tariffs are leveled in nominal dollar terms (i.e., have the same price, unchanging over time) would be reasonable in for the purposes of the COMFIT.

Q. HOW ARE YOU PROPOSING TO INDEX BIOMASS FUEL COSTS?

A. We are proposing to treat biomass fuel cost in the same general manner that the Board approved in the New Page/Port Hawkesbury proceeding.¹ That is, to index 75% of the cost of fuel to a percentage of the Consumer Price Index for Nova Scotia (all items) excluding energy and 25% of the cost of fuel to a diesel fuel index. Costs are indexed to a percentage of the CPI (90% of it) to provide a productivity incentive. According to our model, fuel costs make up 40% of the COMFIT tariff, so the fixed component of the biomass CHP rate would be \$94 per MWh and the escalating component would start in 2012 at \$62 per MWh.

Q. WHAT HAS BEEN YOUR APPROACH TO TARIFF DIFFERENTIATION?

A. The Regulations specify that the Board is to "set a tariff for all of the following classes of electricity generation facility."² Five classes are then listed. We have developed one tariff for each of these five types of facility.

Q. WOULD IT BE POSSIBLE TO DEVELOP FEED-IN TARIFFS FOR OTHER TECHNOLOGIES OR FOR MORE SPECIFIC NARROWER CATEGORIES OF THE SPECIFIED TECHNOLOGIES?

A. Yes, that could be done. In the Renewable Electricity Regulations (Regulations), Government has required certain tariff differentiations. For example, they required one

¹ Nova Scotia Utility and Review Board (NSURB), *Decision In the Matter of an Application by Nova Scotia Power Incorporated for approval of capital work order CI# 39029, Port Hawkesbury Biomass Project, at a cost of \$208.6 million*, 2010 NSURB 196, October 14, 2010.

² See the Renewable Electricity Regulations at Section 18(2).

tariff for wind projects ≤ 50 kW and another for projects > 50 kW, and they required a separate proceeding for the establishment of a developmental tidal tariff. Thus, we take the Regulations to be prescriptive on the point of tariff differentiation, and throughout the stakeholder consultations we have made it clear that we intended to follow the letter of the Regulations and propose one tariff for each resource class.

Q. PLEASE DESCRIBE THE PROJECT TEAM'S OVERALL APPROACH TO THE BALANCING OF COSTS AND POLICY OBJECTIVES?

A. The regulations governing the development of the COMFIT rates clearly call for them to be cost-based. However, the development of such rates requires the exercise of judgment. Our approach has been to balance the impact of the COMFIT program on the cost of electricity against the desire to foster the development of COMFIT projects. To balance the two we have proposed the lowest rates that we believe will result a reasonable level of development activity in each resource class.

Q. PLEASE DISCUSS THE UNCERTAINTIES INVOLVED IN THE PROCEEDS OF SETTING COST-BASED COMFIT RATES.

A. There are large, intrinsic uncertainties involved in setting these rates. In assessing the cost of projects in each resource class, we have had to make assumptions about various parameters for a "typical" project. This includes making assumptions about project size and capacity factor, the specific equipment used, the project owner and the way it is financed. A number of these assumptions have a large impact on the resulting COMFIT rate. For example, we assume a capacity factor of 55% for hydro projects, and assuming a taxable owner, we derive a COMFIT rate of \$138 per MWh. A capacity factor of 60% would yield a rate of \$127 per MWh, and 50% would yield a rate of \$152. For in-stream tidal projects we assume a capacity factor of 37%, and again assuming a taxable owner, we derive a COMFIT rate of \$698 per MWh. A capacity factor of 32% would yield a rate of \$807 per MWh, and 42% would yield a rate of \$615.

Q. IN JUDGING WHETHER YOUR ASSUMPTIONS AND TARIFFS ARE REASONABLE, WHAT HAVE YOU CONSIDERED?

A. We have been careful to consider the reasonableness of each input assumption; however we understand that actual projects will differ from our model projects in many ways. Thus, the important question is, are the proposed *tariffs* reasonable? To address this question we have received a considerable amount of feedback from stakeholders

and other experts; where information is available we have compared our tariffs to the cost of similar existing projects; and we have compared them to FIT prices adopted in other jurisdictions and have considered the market responses in those jurisdictions.

Q. PLEASE DESCRIBE THE PROCESS THAT SYNAPSE HAS LED TO INCORPORATE INPUT FROM STAKEHOLDERS IN THE DEVELOPMENT OF THE COMFIT TARIFFS.

A. We have followed the process outlined in the Board's Order of October 22, 2010. The key milestones in that process were as follows.

- Initial technical session with Intervenors – November 18, 2010
- Written submissions from Intervenors – November 29, 2010
- Draft tariffs proposed by Synapse – December 20, 2010
- Information Requests to Synapse – January 10, 2011
- Responses to Information Requests by Synapse – January 24, 2011
- Second technical session with Intervenors – January 31, 2011
- Final Submissions by Intervenors to Synapse – February 10, 2011
- Final tariffs proposals by Synapse – February 28, 2011

In addition to the draft tariffs required on December 20, we provided revised drafts later in the process, and because some of those revised drafts were not circulated until early February, we accepted Final Submissions from stakeholders after February 10. In addition, to the exchanges of information required in the schedule above, we also had many informal conversations and email exchanges with stakeholders.

Q. WHAT METHOD HAVE YOU USED TO DEVELOP TARIFF RATES?

A. We have entered assumptions about the costs of typical COMFIT projects into a discounted cash flow model and calculated the COMFIT rate that would provide the target, after-tax return on equity to project's owners. For each resource class except biomass CHP, we evaluated the rate that would be needed for a taxable project owner and a non-taxable one, and we are proposing rates based on the average of these two values. For biomass CHP, we have proposed the rate based on a taxable owner, but we evaluated several different types of project.

Q. HOW DID YOU DEVELOP THE SPREADSHEET MODEL USED TO DEVELOP YOUR RATES?

A. The project team reviewed the various models used in other jurisdictions. We began with the discounted cash flow model developed in the proceeding to establish FIT rates in Vermont in 2009. In our judgment this model offered a good level of detail, and most importantly provided for a very open process in which stakeholders could review and comment on any and all inputs, or even run their own calculations if desired. This model was provided to stakeholders for review shortly after the first Technical Session on November 18, 2010. During the stakeholder consultations, we adjusted the model to better suit Nova Scotia as we researched input assumptions for each technology.

C. PROJECT OWNERSHIP

Q. PLEASE DESCRIBE YOUR RESEARCH ON COMFIT PROJECT OWNERSHIP.

A. In the case of wind, hydro and tidal, COMFIT projects must be at least majority owned by one of the following entities: municipalities or wholly owned subsidiaries of municipalities, Mi'kmaq band councils, cooperatives, community-based development corporations, or universities. In the case of biomass CHP, projects may be fully owned by entities other than those on this list, and most of the interest in COMFIT CHP has come from sawmills. In our research, we received comments from, and had discussions with, each type of eligible party listed above.

Many stakeholders indicated that an ownership structure including a private sector partner, or a Community Economic Development Investment Fund (CEDIF), will be necessary to move a project forward, because community-based groups will need assistance raising capital and perhaps expertise in project development. Some stakeholders argued that CEDIFs have had very limited success and that the presence of a COMFIT is not likely to change this. Others were more optimistic. One promising development is the recent success of a CEDIF in financing a 1.5-MW wind project.

Our discussions with stakeholders representing municipalities left us skeptical that these entities will pursue COMFIT projects, given the intense budgetary pressures they are facing. We also discussed a number of issues with representatives of Nova Scotia's First Nations. In terms of project ownership, they said it would be highly unlikely that they would be able to raise the capital without a partner, but that finding a private partner may also be challenging.

Q. WHAT HAVE YOU ASSUMED ABOUT PROJECT OWNERSHIP IN THE MODEL?

A. We have not made specific assumptions about project ownership in developing proposed tariff rates. However, we have considered the extent to which project ownership could affect project costs through the cost of capital and the income tax treatment of the project.

Regarding the cost of capital, we believe that our assumptions regarding these costs will support the successful development of COMFIT projects. Projects with a strong private-sector partner may be in a better position to raise capital, but we do not feel that our cost of capital assumptions will exclude projects without private sector partners. Our research and conclusions on the cost of capital to COMFIT projects are discussed below.

Income taxes affect a project in two ways. Taxable projects incur both the cost of the taxes and the benefit of accelerated depreciation. We find that typically projects are likely to enjoy tax benefits in the early years and liabilities in the later years. The period of liabilities is longer, but it is further out in time, so it is more heavily discounted in the calculation of the IRR. Importantly, we have found the net impact for most resource classes to be quite small. For wind, hydro and biomass, the effect on the COMFIT rate of moving from taxable to non-taxable status ranges from +2.9% for hydro projects to -4.2% for large wind projects. For tidal projects, the impact is larger: -13%. See Exhibit B for a table of these values. (To calculate the rate for a non-taxable entity in the final models, one simply changes the income tax rates to zero and finds the new levelized rate that achieves the target after-tax ROE.)

For wind, hydro and tidal projects, the COMFIT rates we have proposed are the average of the rates calculated assuming a taxable project and a non-taxable project. For biomass CHP projects we have proposed the rate calculated assuming a taxable owner. Note that the models we have provided as Exhibit show the calculations assuming a taxable owner.

D. THE TERMS AND COST OF DEBT

Q. PLEASE DESCRIBE YOUR RESEARCH ON DEBT.

A. We reviewed all comments submitted by stakeholders regarding debt assumptions. Furthermore, we interviewed a broad range of lending experts representing national

banks, credit unions, third-party financing agents, as well as lenders that work specifically with First Nations; we also spoke with project developers on their experience with securing debt financing. Most of these lenders were either located in Canada and/or planned to be active in the Nova Scotia renewable energy markets.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS ABOUT DEBT AND COMFIT PROJECTS.

A. There was consensus among lenders that financing COMFIT projects will be challenging because of the projects' small size, the community-based ownership requirement, 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 be below their minimum lending threshold. A representative of at least one large lending institution, Manulife, reported that it is highly unlikely that they would lend to projects as small as the ones being considered for the COMFIT. 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, most lenders were willing to suggest specific model inputs or provide opinions about values we were considering, and we were able to identify assumptions that a broad cross section of lenders felt were reasonable for the types of projects we were describing. However, all of the lenders added caveats to their opinions, emphasizing that they could only speak in rough terms and that they would need to "run the numbers" for each loan application separately. The assumptions we settled on are summarized in Exhibit C, and each one is discussed briefly below.

- Debt/equity ratio. Both stakeholders and lenders suggested debt:equity ratios could be anywhere from 40%:60% to 70%:30%. There was general consensus that due to the community-based ownership structure and small size of the projects that more equity would be required than if the projects were larger and privately owned. Hydro projects were consistently perceived as less risky than the other technologies. In addition, the lenders we talked to who were familiar with biomass felt that CHP projects could be financed with 60% debt if the question of fuel cost risk were addressed in a satisfactory

1 way. We ultimately settled on 50:50 debt:equity for wind projects and 60:40
2 debt:equity for hydro and biomass CHP projects as a good representation of
3 the information that we gathered from the market. Both lenders and
4 stakeholders urged us to assume that in-stream tidal projects would be
5 financed entirely with equity, due to the high risks perceived with these
6 projects.

- 7
- 8 • Interest rates. For the interest rate, a range of 6% to 14% was suggested by
9 stakeholders and lenders. The low end of this range was generally cited for
10 municipalities and universities, as well as very strong corporate partners. The
11 higher values, particularly rates above 10%, were suggested by some
12 stakeholders for First Nations projects. Many of the lenders we talked with felt
13 that 8% was a reasonable assumption for the wind and hydro projects we
14 were describing, and several lenders suggested 8% without having us first
15 suggest the range we were considering. In our calculations, we have priced
16 debt at 8% for these types of projects.

17
18 The lenders we spoke with who had experience financing biomass projects
19 emphasized the importance of fuel cost risk. These lenders estimated that
20 debt at 8% could only be obtained by a project with a fuel adjustment
21 mechanism in which the energy rate was automatically adjusted based on the
22 project's actual fuel costs. We discussed with them several other ways to
23 address this risk, including the indexing method we have proposed here. In
24 general, they indicated that an assumed interest rate of 8% would be too low
25 for a project with this type of fuel cost indexing. Based on this, we have priced
26 debt to biomass CHP projects at 9.5%. We return to the issue of fuel cost risk
27 in Section E.

- 28
- 29 • Loan amortization period. Lenders and stakeholders suggested loan
30 amortization periods ranging from 5 to 20 years. The majority of feedback
31 was that amortizations in the 10 to 15 year range were reasonable. Some
32 stakeholders felt that a 15-year period might be "aggressive;" however we
33 also heard from lenders that a 15-year amortization was possible, assuming
34 that they were comfortable with the terms of the COMFIT contract. For small
35 wind, however, both lenders and stakeholders tended to agree that a shorter

amortization would be required. Therefore, we assume 15-year amortization for all but small wind systems, for which we assume a 10-year amortization.

Note that in our model, after a project's debt is paid off, its net income is much higher. This does not represent a windfall, because the ROE calculated in the model takes into account both the period during which debt is being serviced and the period following that in which returns to equity investors will be higher.

- Debt Service Coverage Ratio (DSCR). The DSCR compares the cash available in a given year to the amount required to meet debt obligations. Most lenders stated that the projects contemplated under the COMFIT would require an average DSCR of at least 1.5x. We used a 1.5x average DSCR as a constraint; however given the debt:equity ratios and other assumptions we used, we did not have to make adjustments to maintain this ratio.
- Fees and reserve accounts. We assume that lenders charge an up-front fee equal to 1% of the loan value, and that closing costs (including legal and other consulting fees) total 5% of the loan value. We also assume that three reserve accounts are required by lenders: a maintenance reserve, debt service reserve and a working capital account. The sizing of these accounts is shown in Exhibit F.
- Interest during construction. 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. We assume that projects will need separate construction financing. We estimate interest during construction by making the simplifying assumption that 100% of the construction financing is outstanding for half of the construction period. So the formula is: $(\text{Construction Loan Amount}) \times (\text{construction period}/2) \times (\text{annual interest rate}/12)$, where the construction period is stated in months. We assume a one-year loan is needed for large wind, tidal and biomass CHP projects; an 8-month loan is needed for small wind projects and a 1.5-year

loan is needed for run-of-river hydro projects. We assume a 10% interest rate for the construction loan.

E. CAPITAL STRUCTURE AND THE COST OF EQUITY

Q. PLEASE DESCRIBE YOUR RESEARCH AND CONCLUSIONS ABOUT RETURN ON EQUITY.

A. We received a range of comments from stakeholders regarding the return on equity (ROE) that COMFIT projects would need. Some people suggested that communities could tap investors motivated by social and environmental concerns and that these investors would require no return at all. Others felt that the risk associated with some COMFIT projects would require returns as high as 20% or more. It is not surprising that there is such a wide range of views on this issue. There is very little information available with which to benchmark the return on equity needed to attract capital to projects like the ones we are considering – very small projects, owned by small organizations with little experience in developing energy projects but backed by a COMFIT commitment with a very credit-worthy entity.

One approach to determining appropriate returns on equity for COMFIT projects is to assess the risks these projects face in excess of the risk faced by the stockholders of Nova Scotia Power Company Inc. (NSPI). NSPI is currently allowed a 9.35% ROE, and this is the figure the company uses for long term planning purposes.³ 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%.⁴ The Board maintained this ROE for Heritage in a 2009 decision.⁵

³ 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.

⁴ 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.

⁵ Nova Scotia Utility and Review Board (NSURB), *Decision In the Matter of the Gas Distribution Act and In the Matter of Heritage Gas Ltd. For the Approval of Amendments to its Schedule of Rates, Tolls and Charges and Service Rules*, 2003 NSUARB 8, February 12, 2009.

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. We assume that most investors in organizations developing a COMFIT project would be investing, at least initially, in one project. Third, NSPI has the ability to petition the Board for rate increases, while COMFIT projects will not have this ability. And fourth, inexperience and lack of internal expertise among community-based groups could increase risk for these groups relative to a utility project.

In thinking about these four risk factors, it is useful to consider the potential resources in three categories: wind and hydro projects, biomass CHP projects and tidal projects. First, consider wind and hydro projects. 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. 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. 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. On balance, we believe that the return on equity allowed to Heritage Gas (13%) is a reasonable target for these resources.

Next, consider biomass CHP projects. We assume most of these projects will be developed by corporations or universities. These are "going concerns," with significant existing assets and revenues. In some cases, the equity portion of these projects may be financed off of a corporate balance sheet. Where outside capital is sought, investors are likely to perceive less risk in these entities as project developers and owners than in a small, community-based organization. However, biomass CHP projects will face fuel cost risk. As discussed above, we propose to index biomass fuel costs to external factors and to assume a higher cost of debt for biomass CHP than other COMFIT projects. However, our discussions with lenders, stakeholders and other experts leads us to believe that significant risk may still be perceived around biomass projects, even with this fuel indexing and allowance for more costly debt. Thus, we have included a return on equity of 13% for biomass CHP projects, even though the developers of these

1 projects are likely to be seen as less risky than the developers of other COMFIT
2 projects.

3
4 Finally, in-stream tidal projects are unique in that there is vastly more uncertainty about
5 costs and performance than for the other technologies. In-stream tidal projects face
6 tremendous uncertainty about project costs and operation: estimates of installed costs
7 vary by a factor of four. There is very little data from operating projects worldwide, so the
8 reliability of operation and O&M costs are also highly uncertain. Operational problems
9 are to be expected with a technology just emerging from the demonstration stage. If tidal
10 developers put up their own equity, we believe they should receive a return well above
11 the NSPI rate for taking on these risks, and if developers seek outside equity, they will
12 probably have to show very high expected returns relative to NSPI to attract capital. We
13 believe that an appropriate assumption for tidal COMFIT projects is a 15% return on
14 equity.

15
16 **Q. WHAT RETURN ON EQUITY ESTIMATES HAVE BEEN INCLUDED IN THE TARIFF**
17 **PROPOSALS FILED TODAY?**

18 A. We have used a 13% target ROE for wind, hydro and biomass CHP projects, and a 15%
19 ROE for tidal projects. The ROE is defined in the model as the Internal Rate of Return
20 (IRR).

21
22 **Q. WHAT DID YOUR RESEARCH REVEAL ABOUT THE COST OF DEBT AND EQUITY**
23 **TO FIRST NATIONS?**

24 A. Because we have been directed to establish five tariffs, one for each technology, the
25 cost of capital specifically to First Nations was not our primary focus; however we did
26 discuss this issue with several stakeholders and lenders, including representatives from
27 the Membertou Corporate Division, Pictou Landing First Nation, the Assembly of Nova
28 Scotia Mi'kmaq Chiefs, the Bank of Montreal – Aboriginal Banking, the CAPE Fund and
29 Ulnooweg Development Group. The feedback we received was not consistent. Some
30 individuals believed access to capital would not be more difficult or more costly than for
31 other community-based projects (acknowledging that any community-based project will
32 have higher risk), while others were quite clear that capital costs would be higher and
33 access to capital for First Nations projects would be limited. For example, we were told
34 that the interest rate on debt for aboriginal projects could be as high as 14% or as low as
35 6% from sources we consider to be experienced in financing aboriginal projects. We

received similarly wide-ranging feedback for other financial inputs to the model when specifically discussing First Nations projects.

F. TAXES AND DEPRECIATION

Q. WHAT HAVE YOU ASSUMED ABOUT INCOME TAXES IN THE MODEL?

A. When analyzing a taxable entity, we apply a federal tax rate of 15%. Information from the Canada Revenue Agency shows that the corporate income tax rate is currently 16.5% but will be falling to 15% on January 1, 2012.⁶ Based on information from the Nova Scotia Department of Finance, we apply a Provincial tax rate of 4.5% to the first \$400,000 of taxable income and a rate of 16% to taxable income in excess of \$400,000.

Q. HAVE YOU ASSUMED THAT COMFIT PROJECT OWNERS ARE TAXABLE ENTITIES?

A. As described above, we have calculated tariff rates for each resource class assuming that all revenue is taxable and assuming it is not taxable. For wind, hydro and biomass CHP the differences are small; for tidal, the difference is larger. See Exhibit B. Rather than try to predict what the dominant ownership structure will be, we have proposed setting the tariffs at the average of the rates calculated for a taxable owner and a non-taxable owner.

Q. WHAT HAVE YOU ASSUMED ABOUT TAX DEPRECIATION IN THE MODEL?

A. We have assumed that 95% of the installed cost of projects in all five resource classes is eligible for depreciation at an accelerated rate consistent with the Class 43.1 rules laid out in Schedule II of the Income Tax Regulations. Plant eligible for this treatment is depreciated on a 50% declining balance basis, except for the first year of operation. In the first year, only half this amount of depreciation (25%) is allowed. Project development costs, reserve accounts and closing costs and fees are not depreciable.

Based on our reading of these tax regulations, we assume that any interconnection equipment owned by a COMFIT project will not be depreciable for tax purposes.

Q. WHAT HAVE YOU ASSUMED ABOUT PROPERTY TAXES IN THE MODEL?

⁶ See: <http://www.cra-arc.gc.ca/tx/bsnss/tpcs/crprtns/rts-eng.html>.

1 A. For wind projects we have been guided by the Wind Turbine Facilities Municipal
2 Taxation Act. Wind projects ≤ 50 kW do not pay property taxes, and we have
3 approximated the provisions of this act for 1.5-MW projects with a tax rate of 0.4%. We
4 have assumed that other projects pay the posted commercial tax rate, and we have
5 assumed a tax rate (3.5%) roughly consistent with the midpoint of the tax rates in the
6 Province.

7
8 Based on discussions with Property Valuation Services, Corp., (PVS) the group that
9 performs most of the property valuation in Nova Scotia, we do not include "machinery
10 and equipment" in the assessed value of COMFIT projects. Thus, we assume that a
11 percentage of the installed cost of the project is assessable, based on the estimated
12 percentage of those costs that have not gone toward machinery or equipment. Our
13 assessed value percentages range from 1.7% for biomass CHP projects to 50% for
14 hydro projects. Also based on information from PVS, we understand that assessed
15 property values are adjusted every year in the Province, and in this process property is
16 first "indexed up" to its replacement cost and then depreciated based on its age. We
17 simulate the net effect of this process over time as a 1% annual reduction in the
18 assessed value.

19
20 **G. THE COST OF INTERCONNECTION**

21
22 **Q. PLEASE DESCRIBE NSPI'S INTERCONNECTION PROCESS AND REQUIREMENTS.**

23 A. NSPI has separate interconnection processes for generators under 100 kW and over
24 100 kW. For projects under 100 kW, there is no application fee and the interconnection
25 is treated in a manner similar to a service connection. However, the generator is
26 responsible for the cost of required on-site interconnection equipment and of any
27 distribution system upgrades required. NSPI reports that some of the on-site equipment
28 typically required is owned by NSPI and some of it is owned by the customer. As seen in
29 Exhibit D, NSPI estimates the cost of NSPI-owned equipment for projects between 20
30 and 50 kW at \$10,000. (We state figures here as shown in the data NSPI provided, in
31 2011 dollars. These figures have been adjusted to 2012 dollars for input into the model,
32 and they are shown in 2012 dollars in Exhibits E and F.) NSPI did not provide an
33 estimate of the cost of the customer-owned equipment typically required.

For generators over 100 kW, it is useful to consider interconnection costs in the following four categories.

- Required studies
- On site equipment
- Line extension
- Distribution system upgrades

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 typically falls between \$5,000 and \$10,000, with most studies costing less than \$7,500.

On-site interconnection equipment includes equipment located at the generator site. As with projects up to 100 kW, the interconnecting generator pays for all of this equipment, though some of it is owned by NSPI and some is owned by the generator. NSPI's list of the on-site equipment typically required for interconnection is shown in Exhibit D. This Exhibit also shows NSPI's estimate of the typical cost of the on-site equipment owned by NSPI, stated in 2011 dollars. This figure is \$82,500. As for projects up to 100 kW, NSPI did not provide a cost estimate for the customer-owned equipment typically required.

A line extension is needed to deliver power from the generator to the grid when the generator is not located at the distribution system. As seen in Exhibit D, NSPI's estimate of the cost of a line extension is \$55,000 per kW.

Distribution system upgrades are required when the distribution system must be modified in order to accommodate the generator. As seen in Exhibit D, the cost the company has charged or quoted to interconnection applicants for required system upgrades ranges from zero for many projects to \$857,000.

Q. WHAT INTERCONNECTION COSTS HAVE BEEN INCLUDED IN THE TARIFF PROPOSALS FILED TODAY?

A. The interconnection costs included for each project type are shown in Exhibit E.

H. OTHER INPUT ASSUMPTIONS

Q. WHAT OTHER ASSUMPTIONS HAVE GONE INTO THE MODEL?

A. We have also made assumptions about the cost of acquiring equity and the cost of insurance and land lease payments. We have estimated the cost of acquiring equity at 4% of the total equity raised. This could represent the legal, administrative, travel and other costs of establishing a CEDIF and/or the same costs in raising equity from other investors.

Regarding insurance, a major Canadian insurance brokerage provided estimates of insurance rates for projects in each of the five COMFIT resource classes. Stated as a percentage of installed costs, these estimates range from 0.3% for large wind to 2% for tidal. The percentages are shown in Exhibit F.

We estimate the cost of land lease payments for wind projects at 2.5% of annual revenues, based on discussions with people familiar with financing wind projects. For hydro and tidal we assume much smaller payments for an access lease. The size of these payments was suggested by Seaforth Engineering, based on their experience with small hydro projects in the Province. For biomass CHP, we assume that no additional land costs are needed for a CHP plant relative to the steam host's current costs.

I. THE PROPOSED TARIFF WIND ≤50 KW

Q. ON WHAT TYPE OF PROJECT HAVE YOU BASED THE SMALL WIND TARIFF?

A. We have based this tariff on a project with a single 50-kW turbine. The cost and performance assumptions describing this project are shown in Exhibit F.

Q. WHAT HAVE YOU ASSUMED ABOUT THE INSTALLED COST OF THE PROJECT?

A. We assume a total installed cost of \$268,000, including project development costs but not interconnection costs. This assumption is based on information provided by project developers with experience in Nova Scotia and Canada, manufacturers with the same experience and from conversations with the Canadian Wind Energy Association (CANWEA). We spoke to Seaforth, Entegriety (acquired by Seaforth), Endurance, Atlantic Wind, Juwi Wind, Northern Power Systems, SED, EAPC Wind, Community Windfields, and Scotian Windfields. We received actual installed cost data from more than 18 installations of 50-kW turbines in Canada. We then compared these costs to a database of 50-kW projects in the U.S. Aggregated data were used to determine average costs.

1 The installed costs used in the model are within the range of figures reported to us by
2 these developers, manufacturers and CANWEA.

3
4 **Q. HAVE YOU COMPARED YOUR RATE FOR SMALL WIND TO THE RATE**
5 **RECOMMENDED BY CANWEA?**

6 A. Yes. Our total project costs (including interconnection, reserves and fees) come to
7 \$6,427 per kW. This assumption is roughly consistent with CANWEA's recommendation
8 of \$6,100 per kW (adjusted from \$2011), not including interconnection costs. Without
9 interconnection costs, our total project cost is \$6,152 per kW.

10
11 CANWEA has recommended a rate of \$350 per MWh (\$2011) for wind turbines <50 kW.
12 In their Final Submission from February 11, 2011, CANWEA outlined the assumptions
13 underlying this recommendation. We have entered these inputs into our model and
14 removed interconnection costs to be consistent with CANWEA's assumptions. We find
15 that a rate of \$405 per MWh is needed to achieve CANWEA's target rate of return
16 (12%), with a DSCR of 1.4x. If we remove our insurance cost, a rate of \$382 is needed.
17 The difference between \$382 and \$350 appears to result from differences in the
18 structure of the two models.

19
20 **Q. WHAT HAVE YOU ASSUMED ABOUT OPERATING COSTS FOR SMALL WIND?**

21 A. We have assumed operating costs of \$1,642 in year one, including periodic major
22 maintenance. This is calculated as ¢1.63 per kWh, based primarily on information
23 provided by CANWEA. Operating costs are escalated in the model at the general rate of
24 inflation.

25
26 **Q. WHAT HAVE YOU ASSUMED ABOUT THE PROJECT'S CAPACITY FACTOR?**

27 A. We have assumed that small wind projects achieve an annual capacity factor of 23%.
28 This is based on conversations with developers, manufacturers and CANWEA, and on
29 Nova Scotia wind resource maps. While CANWEA suggests using a 20% capacity
30 factor, at least one Canadian project developer has indicated that 25% could be possible
31 in Nova Scotia. The general consensus we found among developers and manufacturers
32 is that 20% is reasonable, perhaps conservative, and that 25% would be on the high-end
33 of expected capacity factors. Therefore we believe that 23% is an appropriate
34 assumption.

35

Q. HOW DOES YOUR PROPOSED RATE COMPARE WITH OTHER BENCHMARKS?

A. In Vermont, the FIT rate for wind projects 100 kW or under starts at \$208 per MWh and escalates to \$230 per MWh over the contract period. As of February 26, 2011, there was one project (100 kW in size) in the queue for this FIT. This is not a particularly robust response. Moreover, three factors suggest that the COMFIT rate for small wind should be significantly higher than the Vermont tariff. First, the Vermont rate is open to projects up to 100 kW, while the COMFIT rate is open to projects up to 50 kW. There are likely to be some economics of scale between 50 kW and 100 kW. Second, projects in Vermont are eligible for either a grant or investment tax credit (ITC) equal to 30% of installed costs. Finally, there is no requirement in Vermont that projects be majority owned by community-based groups. In Ontario, there is no FIT specifically for small wind, and the wind rate has clearly been set at the estimated cost of wind projects well over 50 kW.

J. THE PROPOSED TARIFF FOR WIND >50 KW

Q. ON WHAT TYPE OF PROJECT HAVE YOU BASED THE LARGE WIND TARIFF?

A. We have based this tariff on a single turbine 1.5 MW in size. Our cost and performance assumptions are shown in Exhibit F.

Q. WHAT HAVE YOU ASSUMED ABOUT THE INSTALLED COST OF THE PROJECT?

A. We assume total project costs of \$3.8 million, or \$2,520 per kW, based in large part on conversations with Eon Windelectric Inc., Community Wind Farms, Grupo Guascar, Juwi Wind, EAPC Wind, CANWEA, Community Windfields, Scotian Windfields, and SED. One developer felt that total project costs should be \$4.2 million, while the general consensus was that the \$3.7 million assumption was reasonable. We estimate that our project costs are roughly 11% lower than 2008 project costs, consistent with data showing falling turbine prices since that time.

Q. WHAT HAVE YOU ASSUMED ABOUT OPERATING COSTS FOR LARGE WIND?

A. We have assumed operating costs of \$55,000 per year, including periodic major maintenance. This is based on information provided by developers and manufacturers. We have also included \$1,000 of general and administrative expenses. Both of these expenses are escalated in the model at the general rate of inflation.

Q. WHAT HAVE YOU ASSUMED ABOUT THE PROJECT'S CAPACITY FACTOR?

A. We assume a capacity factor of 31% for wind >50 kW. Wind developers participating in this proceeding have consistently stated that 30% was the appropriate assumption, however the Consumer Advocate and others have argued for a higher capacity factor, based on Nova Scotia's wind resources. In the 2008 Nova Scotia Wind Integration Study prepared for the NS Department of Energy, Hatch Energy states that the capacity factors in four of the six zones studied range from 31% to 35%, and that in two zones the capacity factors are higher.⁷ However, Hatch conservatively uses a capacity factor of 32% for their energy estimates. We have used 31%, representing the midpoint between the wind developers suggestion and the data assumption used by Hatch.

Q. HOW DOES YOUR PROPOSED LARGE WIND RATE COMPARE WITH OTHER BENCHMARKS?

A. We have proposed a flat rate of \$139 per MWh. In Vermont, the FIT for wind between 100 kW and 2.2 MW starts at \$112 per MWh in 2010 and escalates to \$124 per kWh in 2029. On the date of this evidence, there were nine projects in this queue. As noted, the 30% grant/ITC available to projects in the U.S. and the COMFIT requirement that projects be majority owned by a community-based group both suggest a COMFIT rate higher than the Vermont rate.

The FIT rate for on-shore wind in Ontario is \$135 per MWh. On the date of this evidence, contracts had been signed with 49 projects (1,228 MW) and additional 165 projects (7,228 MW) had applications pending. This is an extremely robust response, and we are comfortable proposing a rate only slightly higher than \$135 for COMFIT projects.

We also reviewed confidential Board documents showing prices bid by Nova Scotia wind projects in recent NSPI Requests for Proposals (RFPs). Given the differences between those projects and likely COMFIT wind projects, we are comfortable with our proposed rates relative to those prices.

K. THE PROPOSED TARIFF FOR BIOMASS CHP

Q. ON WHAT TYPE OF PROJECT HAVE YOU BASED THE BIOMASS CHP TARIFF?

⁷ Hatch, *Nova Scotia Wind Integration Study*, prepared for the Nova Scotia Department of Energy, 2008.

1 A. First, there is the question of what kind of steam host to assume. As stated elsewhere in
2 this evidence, we have sought to propose the lowest tariffs that we believe will result in
3 successful COMFIT projects. Thus we have based our calculations on the steam load of
4 a small to medium sized sawmill. We have assumed a steam load of 22 mmBtu/hr for
5 60% of the hours each year. This assumption was suggested by the Alliance of Nova
6 Scotia Sawmills (ANSS) as a typical capacity factor for a sawmill operating under normal
7 conditions, that is, not during a period of very high or low demand for lumber.

8
9 Second is the question of what type of CHP system to base our calculations on, and
10 answering this question has been a challenge. The Regulations state that biomass
11 projects must be “combined heat and power” projects to be eligible for the COMFIT.
12 They do not define how much time a plant must be operating in CHP mode to be
13 considered a CHP plant, nor do they provide a definition of CHP stated as an annual
14 average efficiency. We sought direction on this issue from the Nova Scotia Department
15 of Energy, but they were not able to provide a precise definition of CHP.

16
17 The way COMFIT CHP plants are assumed to operate is critical, because it affects the
18 rate calculation significantly. Further, potential developers of COMFIT CHP projects
19 have told us that it is critical to avoid tying the production of electricity to the operation of
20 the steam host. ANSS has argued that a scenario in which a project could only generate
21 electricity when the host needed steam would be far too risky for any sawmill to pursue.

22
23 **Q. HOW DO ASSUMPTIONS ABOUT THE OPERATION OF A CHP PLANT AFFECT**
24 **THE COST OF ELECTRICITY?**

25 A. They affect the COMFIT rate in three ways. First, the equipment needed to install a
26 system that can generate electricity when steam is not needed is considerably more
27 expensive than the equipment needed for a plant that is operated based on the steam
28 host's needs. For a system based on the host's needs, a back pressure turbine is used.
29 For a system that can be operated in electricity-only mode, a condensing turbine is
30 needed along with a condenser and a slightly more expensive boiler. In addition, a larger
31 turbine is needed for a condensing CHP plant. We estimate the total difference in the
32 capital cost of back pressure and condensing CHP projects at a typical sawmill to be
33 roughly \$4.1 million.

34

The second aspect of plant operation that affects the cost of electricity is fuel use. More fuel is used in a condensing scenario, because the plant operates more, it is larger and it is less efficient than a plant with a back pressure turbine. The additional fuel needed drives up the cost of electricity in the condensing scenario relative to a back pressure scenario. The third important aspect of plant operation is the capacity factor, and this variable works in favor of the condensing scenario. The electric capacity factor is typically higher with a condensing turbine. More electricity generated means more kWhs over which to spread fixed costs and a lower tariff rate.

Q. ARE THERE OTHER IMPORTANT VARIABLES THAT AFFECT THE COST OF ELECTRICITY FROM A CHP PLANT?

A. Yes, one more. A turbine needs steam in order to generate electricity, so some portion of the capital and operating costs of the boiler should be allocated to the electricity produced. To make this allocation, it is common to calculate the cost of a steam-only scenario, in which the facility decides not to pursue CHP. The cost of this scenario is taken to be the facility's going forward cost of steam, something like its avoided cost. This cost is subtracted from the projected cost of the CHP project to calculate the cost of electricity from the project. Making these calculations is common in CHP project development, and it is straightforward when all the variables are known. However, to set a COMFIT rate, we must make an assumption about the existing steam system at the *typical* facility likely to consider a CHP project.

In the case of a facility with a very old boiler that needs to be replaced soon, the avoided cost is high, and this drives down the net cost of electricity from the potential CHP plant. In the case of a facility with a newer boiler, the avoided cost is lower, because the replacement of the existing boiler will not happen for some time. In this case, the net cost of CHP electricity is higher.

Q. HOW HAVE YOU DEALT WITH THE QUESTIONS OF TURBINE TYPE AND THE CONDITION OF THE HOST FACILITY'S EXISTING EQUIPMENT?

A. On the question of turbine type, we believe that tying the operation of a CHP project to the host's steam need would introduce additional risk that, coupled with fuel cost risk, would make it very difficult for COMFIT projects to proceed. Thus, we have proposed a rate based on the cost of a project with a condensing turbine. Regarding what to assume about the existing equipment at the "typical" sawmill, we sought information from the

1 sawmills in the Province. We asked the sawmills, through ANSS, some questions about
2 their existing boilers, making it clear that the information would be treated as
3 confidential. No sawmill answered these questions. Our request for information about
4 existing boilers and steam production, emailed to representatives of ANSS on February
5 7, 2011, is attached as Exhibit G.

6
7 To explore this issue, we examined the cost of electricity in two condensing turbine
8 scenarios. In one scenario we assumed that the host facility's existing boiler needed to
9 be replaced immediately, and in the other, we assumed that it had an additional 10 years
10 of useful life.

11
12 **Q. WHAT DID THIS SCENARIO ANALYSIS SHOW?**

13 A. The COMFIT rates for the two scenarios are shown below.

- 14 • At a facility that needs a new boiler imminently – \$147 per MWh;
- 15 • At a facility that will need a new boiler in ten years – \$156 per MWh.

16 As expected, the cost of electricity is lower at a facility that needs to replace its existing
17 equipment immediately, because the going forward cost of generating steam only is
18 higher. The other useful thing to note is that the cost does not rise particularly sharply for
19 facilities that have some useful life left on their equipment. Given the assumptions we
20 have made, assuming ten years of life left only increases the cost of electricity by about
21 6%.

22
23 **Q. WHAT RATE ARE YOU PROPOSING FOR THE BIOMASS CHP TARIFF?**

24 A. Based on the information we have received from stakeholders and our analysis of these
25 scenarios, we propose a COMFIT rate of \$156 per MWh. First, we believe that it is
26 appropriate to base the tariff on the cost of a scenario in which a condensing turbine is
27 installed and some of the electricity sold on the COMFIT is generated in electricity-only
28 mode. Second, not having information on the state of any existing host facilities in the
29 Province, we believe that \$9 per MWh is a reasonable increment to pay so that more
30 facilities than those with the highest avoided cost can consider CHP in the near term.
31 However, we understand that the level of avoided cost assumed in the model is a policy
32 decision that requires a weighing of costs to ratepayers against the goals of the COMFIT
33 program.

Q. HOW DOES THIS RATE COMPARE WITH OTHER BENCHMARKS?

A. The Vermont biomass FIT starts at \$121 per MWh in 2010 and escalates to \$141 in 2019 (in nominal dollars). Projects are required to be CHP projects, are required to meet a “design system efficiency” of 50%, but are not required to be community owned. Biomass projects in Vermont are also eligible for the same 30% grant or ITC as wind costs. At the date of this evidence, four biomass CHP projects, ranging from 400 kW to 2.2 MW had applied for the biomass FIT and were moving forward. Given the impact of the 30% subsidy in Vermont, and the requirement for community-based ownership in the COMFIT, we would expect that a rate significantly higher than the Vermont rate would be needed to produce successful COMFIT projects.

The FIT rate for biomass <10 MW in Ontario started in 2010 at \$138 per MWh, or \$142 per MWh for community-owned projects, and 20% of this rate escalates with inflation. There is no requirement for CHP in the Ontario biomass FIT. At the date of this evidence, contracts had been executed with 2 projects (17 MW), and applications were pending for 7 more (57 MW). The fact that these are larger projects than allowed in the COMFIT suggests that the COMFIT rate should be higher than the Vermont rate, but the fact that they are electricity-only projects suggests that perhaps the COMFIT rate should be lower than the Vermont rate.

Finally, we have reviewed confidential Board documents stating the terms at which NSPI will purchase electricity from the 60 MW New Page/Port Hawkesbury project. Given the differences between this project and likely COMFIT projects, we are comfortable with the position of our proposed rate relative to that one.

Q. WHAT HAVE YOU ASSUMED ABOUT THE INSTALLED COST OF A BIOMASS CHP PROJECT?

A. In each of the two scenarios, we priced out a steam-only case and a CHP case, and we entered the net values into the cash flow model to calculate the COMFIT rate. We sized the boiler in the steam-only cases at 20,000 lb/hr and assumed a design pressure of 75 to 100 lbs. In the CHP cases we assumed a 30,000 lb/hr boiler for a condensing turbine and a 20,000 lb/hr boiler for a back pressure turbine, both with design pressures of 600 lbs. We assumed an annual capacity factor of 60% for the back pressure system and

85% for the condensing system. The condensing system was assumed to operate 60% of annual hours in extraction mode (i.e., providing steam to the host) and 25% of the hours generating electricity only (i.e., in full condensing mode). This yields an annual average efficiency of 52%. In the scenarios where the existing steam boiler is at the end of its useful life, we included the full cost of a new boiler when assessing the steam-only case. In the scenarios where the existing boiler is assumed to have ten years of life left, we used the same boiler costs, but discounted them by ten years using our assumed inflation rate of 1.92%.

For a new boiler purchased immediately, the installed cost is based on an estimate from KMW, a Canadian supplier of biomass boilers in this size range. At the time of the boiler replacement, we assume that an electrostatic precipitator is added for air pollution control, at a cost of \$305,760. This assumption is based on information provided by Nova Scotia Environment on the particulate matter emission standards likely to be in effect during the COMFIT contract period.

The CHP cases used the same boiler estimate, increased by 50% to represent a 30,000 lb/hr boiler with a design pressure of 600 lbs. The same emission controls were assumed as in the steam-only scenario. The cost of the air-cooled condenser was based on an estimate from a manufacturer, SPX. Development costs were included to cover engineering, administrative costs of applying for the tariff, and environmental permitting. Steam turbine generator costs were from an estimate provided by Turbosteam, a manufacturer of turbine generators in this size range.

The input assumptions for both scenarios we examined are laid out in Exhibit F.

Q. WHAT HAVE YOU ASSUMED ABOUT OPERATING COSTS FOR BIOMASS CHP?

A. Routine O&M costs were developed through discussions with operators of similar biomass fired facilities in PEI and Ontario. The costs are substantially the same for both the steam-only and CHP scenarios, the main differences being an increased cost in the CHP scenario for a larger boiler and for operating and maintaining a steam turbine and condenser not found in the steam-only case. There is also an increased cost in years 1-9 for the steam-only case with a boiler replacement in year 10 to account for equipment approaching its end of life.

Both the steam-only plant and the CHP plant would require attendance while in operation under the Nova Scotia regulations. We have assumed that one additional person is needed to operate the CHP plant relative to the steam-only system.

Fuel usage was determined using a boiler plant efficiency of 80%, which is higher than some reported data in this size range, but is also lower than the 85% documented by an operator in PEI. Electricity production was calculated with steam turbine efficiencies provided by the turbine supplier that provided the capital cost estimate. Current fuel prices are based on information provided by COMFIT stakeholders. We assume fuel prices of \$36 per ton, a moisture content of 50% and a heat content of 4,250 Btu/lb. This yields a fuel cost assumption of \$4.24 per mmBtu.

Q. WHAT HAVE YOU ASSUMED ABOUT CHP PLANTS' CAPACITY FACTOR?

A. As the tariff will require the biomass application to be combined heat and power, there are capacity factors involved with both the heat and the power generation. For the total availability of a biomass fired system, 85% was used to allow for scheduled and unscheduled maintenance. Thus 85% of the time, steam and/or power is being produced. This is consistent with our experience with biomass and solid waste combustion systems, and it takes into account fuel handling issues and the higher boiler maintenance requirements of non-homogeneous solid fuel.

The project model assumes that power is being produced at all 85% of hours, and that heat for process use is extracted 60% of the time. The 60% figure is 5,256 hours per year, or about 100 hours per week. A 100 hour week is the equivalent of a sawmill running at two shifts per day, 5 days per week, and a single shift on Saturday and Sunday. However, since the forest products industry is cyclic, we have examined the sensitivity of our results to this assumption. We found that, as the steam need falls, a higher COMFIT rate is needed to maintain the 13% IRR, but the rate does not rise sharply. For example with a steam capacity factor of 40%, a rate of \$164 per MWh is needed and at a steam capacity factor of 20% a rate of \$172 per MWh is needed. Looked at in another way, at a steam capacity factor of 40% and our proposed COMFIT rate of \$156 per MWh, a project's return on equity would fall to 9.6%. A table showing the results of this sensitivity analysis is included as Exhibit H.

However, note that as the steam load falls, the annual efficiency of the plant falls too. At a 40% steam capacity factor annual plant efficiency falls to 40% and at a 20% steam capacity factor efficiency falls to 29%. We believe that including fuel costs in the model consistent with an annual average efficiency of 52% is consistent with the spirit of the CHP requirement in the regulations.

L. THE PROPOSED TARIFF FOR RUN-OF-RIVER HYDRO

Q. ON WHAT TYPE OF PROJECT HAVE YOU BASED THE HYDRO TARIFF?

A. We have based this tariff on a 1-MW project of either the penstock or in-river type. At a penstock plant, water is diverted from the river through a conduit (the penstock) to a turbine located on land and then back to the river. At an in-stream project, the turbine is located in the river. Based on our discussions with stakeholders and other knowledgeable individuals, we believe the costs of these two project types, given an attractive site, are similar in magnitude. In the case of a penstock project, there is the added cost of the penstock, and in an in-stream project the cost of the powerhouse is higher, because it is located in the river. Thus, we believe that the tariff proposed here could support either a penstock or in-stream project at an attractive site.

Q. WHAT HAVE YOU ASSUMED ABOUT THE INSTALLED COST OF THE PROJECT?

A. We assume an "Equipment & Installation" cost of \$3.9 million dollars, and a total project cost of \$4,447 per kW, including interest during construction and all fees related to financing. We include these elements in "Equipment and Installation" costs for hydro projects because the sources on which we relied did so. One source we relied on for this estimate is information used in the Vermont FIT proceeding in 2009. In this proceeding, \$4,400 per kW (adjusted from \$2009) was used for hydro projects in the range of 1.2 MW. This assumption was based on data from three recent projects in Vermont: a 675 kW project developed by Great Bay Hydro in Charleston and 960 kW and 2.2 MW projects developed by Community Hydro in Townshend and Jamaica.⁸ We also relied on two Canadian studies of hydro costs and potential. In 2005, Hatch Acres estimated the cost for a 0-5 MW project to be in the range of \$4,400 per kW for a project at an existing

⁸ See Vermont PSB Docket 7523: Cost Analysis Subgroup, *Report and Recommendations of the Cost Analysis Subgroup under Docket 7523, Appendix B – Summary of Assumptions*, August 28, 2009.

dam to \$5,100 per kW for a project at a greenfield site (both adjusted from \$2005).⁹ A 2007 study by CanmetEnergy presented cost estimates based on project capacity and head height. The estimate for a 5-MW project with a head between 5 and 15 meters ranges from \$3,400 to \$5,900 per kW (adjusted from \$2000).¹⁰

Q. HAVE YOU INCLUDED A RESIDUAL VALUE FOR HYDRO PLANTS AT THE END OF THE COMFIT CONTRACT?

A. Yes. Hydro is the only resource class for which we include a significant residual value, and we do this for hydro because of the relatively long useful life of some of the structures and equipment at a hydro site. We calculate the residual value by estimating the percentages of the installed costs with useful lives of various lengths.

Generally we assume that the structures, civil engineering work and some components of the electromechanical equipment (e.g., the turbine casing) have useful lives of 50 years. We assume the rest of equipment has a useful life of 20 years. Hatch Energy estimates that the civil work at a small hydro site is typically 25% of the cost and the electromechanical equipment is typically 53% of the cost.¹¹ These figures suggest that something like 35% of installed costs might be reasonably considered to have a useful life of 50 years. However, Seaforth Engineering estimates this percentage to be over 75% of installed costs. Based primarily on these two sources, we depreciate half of the installed cost of equipment over 50 years and half of it over 20 years to arrive at a residual value. The calculated tariff rate is not sensitive to the amount of equipment that is assumed to last 50 years. Assuming that 75% or 25% of the equipment lasts 50 years only changes the COMFIT rate by plus or minus 1.4%.

Q. WHAT HAVE YOU ASSUMED ABOUT OPERATING COSTS FOR HYDRO PROJECTS?

A. We assume \$50,000 per year for equipment O&M and \$157,250 per year for “all-in” O&M, including insurance and property taxes. The \$50,000 figure includes the

⁹ Hatch Acres, *Evaluation and Assessment of Ontario's Waterpower Potential*, prepared for the Ontario Waterpower Association and the Ontario Ministry of Natural Resources, October 2005. (Hereafter: “Hatch Acres 2005.”)

¹⁰ CanmetEnergy, *Emerging Hydropower Technologies R&D in Canada: A Strategy for 2007 to 2011*, December 2007. Hereafter: “CanmetEnergy 2007.”

¹¹ Hatch Energy, *Low Head Hydro Market Assessment: Volume 1 Main Report*, written for Natural Resources Canada, March 2008, report number H-327842. See Table 5-2. (Hereafter: “Hatch Energy 2008.”)

annualized cost of periodic major maintenance. We arrived at this assumption by reviewing data provided in the Vermont FIT proceeding and a report by Hatch Energy¹² and through discussions with Seaforth Engineering.

Q. WHAT HAVE YOU ASSUMED ABOUT THE PROJECT'S CAPACITY FACTOR?

A. We assume an annual average net capacity factor of 55%. Hatch Energy's *Low Head Hydro Market Assessment* includes an estimate of 60%, and Seaforth Engineering also suggested 60% as a reasonable assumption.¹³ However, data provided in the Vermont FIT proceeding led to an assumption of 45%.

The FIT for small hydropower in Vermont started in 2010 at \$119 per MWh and escalates to \$131 per MWh in 2029 (in nominal dollars). On the date of this evidence, 7 projects were in the Vermont hydro queue, ranging in size from 50 kW to 1.1 MW. These projects are very similar in size to probable COMFIT projects. However they are not required to be majority owned by a community-based group, and they will benefit from the 30% grant/ITC available in the U.S. Thus, we would expect that a rate significantly higher than the Vermont rate would be needed to produce similar COMFIT development activity.

Ontario's FIT for hydro ≤10 MW started in 2010 at \$131 and \$135 for community owned projects, and 20% of the rate escalates with inflation. Adjusting these figures to 2012 dollars, the community based rate is almost exactly the same as the rate we have proposed, \$140 per MWh. On the date of this evidence, 44 contracts had been signed with hydro projects totaling 183 MW. In addition, 37 projects had applied to the program, totaling 152 MW. We do not know the sizes of these projects or if any of them are community owned.

M. THE PROPOSED TARIFF FOR SMALL, IN-STREAM TIDAL ENERGY

Q. ON WHAT TYPE OF PROJECT HAVE YOU BASED THE TIDAL TARIFF?

A. We have based this tariff on a 500-kW installation employing one or more small, in-stream tidal generators. Examples of this technology include the TGU made by Ocean Power Generation Systems (ORPG) and the Encurrent turbine made by New Energy

¹² Hatch Energy, 2008.

¹³ Hatch Energy 2008, Table 5.4.

Corp. With both of these generator types, multiple machines would need to be installed in order to achieve 500 kW of capacity. We are not aware of technologies that would be eligible for the COMFIT in-stream tidal tariff that are lower cost than these types of system. There is considerable information available about in-stream generators larger than 0.5 MW, such as turbines made by Lunar Energy, Marine Current Turbines and Verdant Power, and barrage tidal systems are available, but these are not considered “in-stream” generators. We have selected the 500-kW size based on discussions with tidal developers in Nova Scotia, who expect the first installations in the Province to be small in order to minimize complexity and risk while gaining operating experience.

Q. WHAT HAVE YOU ASSUMED ABOUT THE INSTALLED COST OF THE PROJECT?

A. We have assumed total project costs of \$5 million, or \$10,076 per kW, based on information from studies, from several projects proceeding outside of Nova Scotia and from tidal developers within the Province. The range of estimated costs is much larger for tidal than the other technologies, and this is to be expected given the immaturity of this technology. A 2010 study by Ernst & Young of the tidal potential in the U.K. estimated the cost of in-stream tidal projects at \$18,100 per kW in the pre-demonstration phase and \$7,000 in the demonstration phase (adjusted from £2010).¹⁴ The Canoe Pass project in British Columbia, which will use the Encurrent turbine, has estimated costs at \$13,000 per kW (adjusted from 2011\$). Fundy Tidal estimates costs at \$10,600 per kW, and Champlain Tidal Energy estimates costs at \$10,200 per kW for pilot projects and \$5,100 per kW for early production projects (all adjusted from 2011\$).

Q. WHAT HAVE YOU ASSUMED ABOUT OPERATING COSTS FOR TIDAL PROJECTS?

A. We have assumed \$75,000 in routine O&M, calculated as \$150 per kW. We also include a \$62,500 major maintenance event every 6 years. The Ernst & Young study estimates “all-in” O&M costs of \$766 per kW in the pre-demonstration stage and \$503 per kW in the demonstration stage (adjusted from £2010). However, one developer shared with us a detailed business plan for a project in Nova Scotia which included estimates of operating costs significantly lower than these. Thus, our O&M cost assumptions are based on this information.

¹⁴ Ernst & Young, *Cost and financial support for wave, tidal stream and tidal range generation in the UK*, prepared for the Department of Energy and Climate Change and the Scottish Government, October 5, 2010. (Hereafter, “Ernst & Young, 2010”)

1
2 **Q. WHAT HAVE YOU ASSUMED ABOUT THE PROJECT'S CAPACITY FACTOR?**

3 A. We have assumed a capacity factor of 37% for tidal projects. There is very little
4 operating data with which to predict the capacity factor of in-stream tidal generators. One
5 report assumes capacity factors for larger units, such as the MCT and Lunar Turbines
6 machines, at 40%.¹⁵ Discussions with developers working with the smaller machines that
7 would be eligible for the COMFIT tariff believe that 35% is a better assumption for these
8 machines. With little other evidence to go on, we have used an assumption between
9 these two estimates.
10

¹⁵ Electric Power Research Institute (EPRI), *Nova Scotia Tidal In-Stream Energy Conversion (TISEC): Survey and Characterization of Potential Project Sites*, EPRI - TP- 003 NS Rev 2, October 2, 2006.

Exhibit A:
Submitted with the Evidence of Bruce Biewald, Wilson Rickerson,
Geoff Keith and Susan Shaw

Background and Qualifications of the Sponsors

Bruce Biewald

Mr. Biewald is the founder and President of Synapse Energy Economics. Since 1980, he has analyzed the electricity industry and advised state agencies, consumer and environmental advocates, utilities, and others on issues related to the production and consumption of energy. He has testified in more than one hundred cases including utility regulatory proceedings in twenty-five states, the Federal Energy Regulatory Commission, the Nuclear Regulatory Commission's Atomic Safety and Licensing Board, two Canadian provinces, and in State and Federal Courts.

Mr Biewald has co-authored more than one hundred reports, including studies for the Electric Power Research Institute, the U.S. Department of Energy, the U.S. Environmental Protection Agency, the U.S. Department of Justice, the Office of Technology Assessment, the Interfaith Center on Corporate Responsibility, the Civil Society Institute, the New England Governors' Conference, the New England Conference of Public Utility Commissioners, the National Association of Regulatory Utility Commissioners, and the United Nations Framework Convention on Climate Change. His papers have been published in the Electricity Journal, Energy Policy, Public Utilities Fortnightly, and numerous conference proceedings.

Mr. Biewald's resume is attached below.

Wilson Rickerson

Mr. Rickerson has worked with a range of stakeholders on renewable energy policy design at the municipal, state and international level, and with feed-in tariff design specifically. Since 2008, he has worked as a consultant to the California Energy Commission, assisting with the development of feed-in tariff design recommendations. He supported Renewable Energy Vermont (REV) as a consultant during the Docket 7523 and 7533 proceedings on Vermont's Standard Offer Contract. He recently concluded a project working with a team of consultants to conduct a study of feed-in tariff rate setting methodology and build a feed-in tariff rate setting model for the US National Renewable Energy Laboratory.

Mr. Rickerson is currently under retainer to support feed-in tariff policy development in the US for Rockefeller Brothers Fund. Internationally, he has worked with the Heinrich Böll Foundation to conduct a series of international feed-in tariff policy dialogue and research projects since 2006. In early 2010 he worked with Deutsche Bank Climate Change Advisors to develop the Global Energy Transfer Feed-in Tariff (GET FiT) concept in response to a request from the UN Secretary General's Advisory Group on Energy and Climate Change. As part of that project, he

helped analyze how international climate finance mechanisms could support existing FITs in developing countries, and conducted outreach to over 100 international stakeholders. He also supported the development of Deutsche Bank's TLC FIT analysis approach, which was published in the report: *Paying for renewable energy*. For the Inter-American Development Bank, he supported a project to propose feed-in tariff designs for two countries in the Latin America and Caribbean region.

Mr. Rickerson's resume is attached below.

Geoff Keith

Geoff Keith has worked as an energy and environmental consultant for 15 years. He has assessed market opportunities around clean energy for several large energy companies and represented environmental advocacy groups in proceedings to develop renewable portfolio standards and electricity disclosure requirements. He has led numerous research and modeling efforts, such as the development of a Distributed Resource Emissions Model, designed to assess the emissions impacts of policies related to distributed generation, and hourly dispatch modeling of demand response programs in the Northeastern U.S.

Mr. Keith has tracked the cost and performance of renewable energy technologies throughout his career, and he has contributed to several integrated regional energy plans. He has built a number of spreadsheet models for clients, including one designed to explore the cost of integrated renewable energy strategies in nine U.S. regions and another designed to assess marginal emission rates in several power control areas.

Mr. Keith's resume is attached below.

Susan Shaw

Ms. Shaw has spent nearly 30 years working in energy generation. Her experience includes engineering, operations, maintenance and financial responsibility of power plants. She has worked with waste-to-energy systems of up to 2,600 tons per day and 90 MWe, numerous district energy combined heat and power plants and wood-fired systems in Canada.

Ms. Shaw is a graduate of Georgia Tech and a Professional Engineer licensed in Ontario and Nova Scotia. She is a past-president and was a 10-year Board member of the Canadian District Energy Association.

Ms. Shaw's resume is attached below.

Bruce Edward Biewald

President

Synapse Energy Economics, Inc.
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bbiewald@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. President, 1996 to present.

Consulting on issues of energy economics, environmental impacts, and utility regulatory policy, including electric power system planning, air emissions, climate change policy, market power, mergers and acquisitions, generation asset valuation and divestiture, nuclear and fossil power plant costs and performance, renewable resources, power supply contracts and performance standards, green marketing of electricity, nuclear plant decommissioning and radioactive waste issues, environmental externalities valuation, energy conservation and demand-side management, electric power system reliability, avoided costs, dispatch modeling, economic analysis of power plants and resource plans, portfolio management, risk analysis and risk management.

Tellus Institute, Boston, MA. Senior Scientist and Manager of the Electricity Program, 1989 to 1996, Research Associate and later Associate Scientist, 1980-1988.

Responsible for research and consulting on all aspects of electric system planning, regulation, and restructuring.

EDUCATION

Massachusetts Institute of Technology,
BS 1981, Architecture, Building Technology, Energy Use in Buildings.
Harvard University Extension School,
1989/90, Graduate courses in micro and macroeconomics.

SUMMARY OF TESTIMONY, PUBLICATIONS, AND PRESENTATIONS

Expert testimony on energy, economic, and environmental issues in more than one hundred utility regulatory proceedings in twenty six states and two Canadian provinces, in cases in State and Federal Courts, and in proceedings of the Federal Energy Regulatory Committee and the Nuclear Regulatory Commission's Atomic Safety and Licensing Board.

Co-author of more than one hundred reports, including studies for the Electric Power Research Institute, the U.S. Department of Energy, the U.S. Environmental Protection Agency, the Office of Technology Assessment, the New England Governors' Conference, the National Association of Regulatory Utility Commissioners, and the United Nations Framework Convention on Climate Change.

Papers published in the Electricity Journal, the Energy Journal, Energy Policy, Public Utilities Fortnightly, and numerous conference proceedings.

Invited to speak by American Society of Heating, Refrigerating, and Air-Conditioning Engineers, American Society of Mechanical Engineers, International Atomic Energy Agency, National Association of Regulatory Utility Commissioners, National Association of State Utility Consumer Advocates, National Consumer Law Center, the Latin American Energy Association (OLADE), the Swedish Environmental Protection Agency (SNV), the U.S. Environmental Protection Agency, the European Federation of Clean Air and Environmental Protection Associations, and others.

WILSON H. RICKERSON

98 N. Washington Street, Suite 302, Boston, MA 02114
tel: 617.934.1676 • fax : 617.517.7732 • email: wilson.rickerson@mc-group.com

PROFESSIONAL EXPERIENCE

CEO, Meister Consultants Group, Inc., Boston, MA (2006-present)

- Managing the international clean energy and climate change consulting practice for a 100-person transatlantic company.
- Completed numerous feed-in tariff analysis and design studies, including:
 - *National Renewable Energy Laboratory (NREL)*. Working with a team of consultants to build a feed-in tariff rate setting model for states and cities, conduct a legal analysis of potential US state/federal policy conflicts, conduct a review of feed-in tariff interconnection best practices, and review NREL's feed-in tariff design best practices research.
 - *California Energy Commission (CEC)*: Supported the development of a proposed feed-in tariff design as a means to meet California renewable energy goals. Developed a feed-in tariff design analysis framework for a multi-year stakeholder process, and researched the financing implications of feed-in tariff design choices, international feed-in tariff rate setting methodologies, and on the interplay between feed-in tariffs and transmission planning.
 - *Hawaiian Electric Company (HECO)*. Supported HECO's participation in the state feed-in tariff design regulatory process. Supported the development of a proposed feed-in tariff design, surveyed international best practices and benchmarked Hawaii's efforts against feed-in tariff design efforts in the US and Canada.
 - *Renewable Energy Vermont*. Provided testimony and analysis to support the development of Vermont's feed-in tariff regulations on behalf of a renewable energy industry association. Conducted research on feed-in tariff rate setting best practices and assisted with the development of a consensus rate setting model.
 - *DB Climate Change Advisors*: Served as a technical advisor and contributor to a Deutsche Bank study of global renewable energy policies, focusing on feed-in tariff designs in developing countries, in response to a request from the UN Secretary General's Advisory Group on Energy and Climate Change. Proposed feed-in tariff program design for multi-lateral donor organizations, following consultation with over 130 experts in the fields of renewable energy, international development, and finance.
 - *SEMI PV Group*. Served as the technical advisor to the global semiconductor association's photovoltaic division, the SEMI PV Group. Worked with SEMI to develop a consensus solar energy policy position on feed-in tariffs based on international best practices. The findings were published in a white paper, *Advancing a Sustainable Solar Future*.

Policy Advisor, Center for Sustainable Energy at Bronx Community College, Bronx, NY (2005-present)

- Coordinated the City University of New York's (CUNY) Million Solar Roofs partnership with the US Department of Energy (DOE).
- Supported the development of the City of New York's Solar City Partnership, including New York's unique property tax abatement for renewable energy.
- Managed municipal energy efficiency and renewable energy projects, and implemented sustainable energy programs for public facilities and college campuses.

Research Associate, Center for Energy & Environmental Policy, Newark, DE (2003-2005)

- Served as the legislative assistant to the Delaware Senate Energy & Transit Committee. Drafted Delaware's renewable portfolio standard and performance contracting legislation.
- Implemented a project modeling photovoltaic systems and energy efficiency technologies installed through performance contracts on public buildings.

Associate Director, Solar New York, New York State (2003).

- Developed strategies for a public interest campaign in support of innovative solar energy financing models.
- Worked with the State of New York to integrate photovoltaic technologies into existing performance contracting programs.

Intern, Bundesverband WindEnergie e.V. (BWE), Berlin, Germany (2002).

- Worked with the German Wind Energy Association during a professional exchange sponsored by the US Congress and the German Bundestag.
- Researched international wind energy policy with BWE Berlin Director, and prepared reports on German renewable energy laws for a European Union project.

Associate, Development Alternatives, Inc., Bethesda, MD (1998, 1999-2000).

- Supported international development projects in Jamaica, Ghana and the West Bank from DAI headquarters.
- Managed European Union and USAID contracts in which members of the Polish Parliament studied regional economic development in the US and Canada.

EDUCATION

Masters in Energy and Environmental Policy (MEEP), University of Delaware (2005)

- Energy and Environmental Policy Excellence Award
- American Association of Geographers Earl Cook Award for paper on energy and the environment

Scholarship, Congress-Bundestag Youth Exchange for Young Professionals, Germany (2001-2002)

B.A., Double Major, International Relations & Literary and Cultural Studies, College of William & Mary (1999)

LANGUAGES

English (native), German (proficient), French (basic)

COMPUTER SKILLS

RETScreen[®] (trained as trainer), PV Planner

PROFESSIONAL ASSOCIATIONS & HONORS

- Editorial Board Member, *BioCycle* magazine
- Advisory Board Member, Solar America Board for Codes and Standards
- Board Member, IFOK GmbH
- Policy Fellow, Center for Energy and Environmental Policy
- Planning Committee Member, World Renewable Energy Conference 2010 (Abu Dhabi, UAE), Northeast Sustainable Energy Association Building Energy 09 Conference (Boston, MA), & World Wind Energy Conference 2008 (Kingston, ON).
- Member, American Wind Energy Association, International Solar Energy Society, American Solar Energy Society, New England Clean Energy Council, Northeast Sustainable Energy Association
- NABCEP[®] PV Entry-Level Certificate of Knowledge
- Peer Reviewer, *Energy Policy* journal

Geoffrey L. Keith

Associate

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. Associate, 2001-2006, 2009-present. Areas of focus include environmental and economic analysis related to power generation and regional power systems; renewable energy costs and characteristics; and analysis of the U.S. fleet of fossil-fueled power plants. Examines regional scenarios for reducing greenhouse gases from the power sector and models power systems to assess costs and environmental impacts of policy proposals. Has led projects for clients including the Natural Resources Defense Council, the Ozone Transport Commission, Sierra Club, and the Hudson River Foundation.

M. J. Bradley & Associates, Concord, MA. Environmental/Energy Consultant, 1996-2001. Worked with environmental advocates and energy companies in support of more stringent air regulations and energy policies supporting clean energy technologies. Facilitated strategic partnerships to address regulatory and market barriers to distributed generation. Participated in regulatory and legislative proceedings relevant to renewable resources and distributed generation and coordinated communication between technology developers, advocates and energy and air regulators.

Rhode Island Division of Public Utilities and Carriers, Providence, RI. Policy Analyst, 1995-1996. Analyzed the economic and environmental implications of electric industry restructuring proposals. Helped facilitate the Rhode Island Electric Industry Restructuring Collaborative and co-authored the Division's restructuring plan.

Institute for Resource and Security Studies, Cambridge, MA. Intern, 1992. Managed research projects including the creation of a sustainability database for the City of Cambridge and a report on energy use in the city.

National Outdoor Leadership School, Lander, WY. Field Instructor, 1989-1990. Completed instructors training program. Responsibility for the safety and education of students on 30-day wilderness expeditions in Alaska. Organized and led a 30-day trek in the Himalayas.

EDUCATION

- Masters, Environmental Studies. Brown University, Providence, RI, 1995.
- Post-baccalaureate work, chemistry, statistics and economics. Harvard Extension School, Cambridge, MA, 1993.
- B.A., English. Tufts University, Medford, MA, 1988.

Resume dated August 2010.

Susan Shaw, P.Eng.

421 Baker Street
London, Ontario N6C 1X8
srshaw@rogers.com
519.433.5885

PROFESSIONAL EXPERIENCE

SunConnect Canada ULC

August 2010 – February 2011

London, Ontario

FIT Program Manager

- Managed FIT process for Ontario solar rooftop photovoltaic installations.

CORIX Utilities Inc.

September 2009 – January 2010

London, Ontario

Manager, Project Development

- Developed and advanced development of wind, geothermal and district energy projects.

EPCOR Utilities Inc.

January 2005 – June 2009

London, Ontario

Director, Ontario Region Business Development

- Responsible for business development for power and water projects in the provinces east of Saskatchewan
- Managed group of business development managers
- Awarded contracts in the Ontario Power Authority's RFPs for Renewable Energy Supply I and II, participated in the GTA West RFP, and qualified for the Combined Heat and Power I RFP and Northern York Peaking Facility RFP. The Kingsbridge I wind farm, awarded under RES I, became the highest capacity factor wind project in Ontario.
- Shortlisted for municipal water RFPs in Cavan-Millbrook-North Monahan (Ontario) and Red River (Manitoba)

Enable Consulting Inc.

June 2001 – December 2004

London, Ontario

President

- Enable Consulting provided professional services for energy projects. These services included:
 - Providing analysis and advice to support due diligence for clients' district energy acquisitions
 - Feasibility studies for cogeneration projects
 - Review and analysis for cost reduction of clients' electricity profiles, including load management and load shifting
 - Consultation and advice on the implications of Ontario's electricity deregulation
 - Preparing requests for proposals and evaluating results for clients' electricity purchases

Enable's clients included industrial businesses, independent power producers, governments, hospitals, school districts, residential and commercial developers and building owners.

Trigen Energy Canada Inc.

August 1997 – June 2001

London, Ontario

President

- Supervised operations of two district energy systems with combined annual revenues of \$14M, and 50 employees
- Responsible for the results of the operations, from strategic planning and budgeting up to and including financial performance
- Improved financial results from negative to positive cash flow, making units viable for divestiture
- Directed external communications for these units

Trigen Energy Corporation

February 1994 – February 1999

White Plains, New York

Director, Operations Engineering

- Managed a group of 5 engineers, providing assistance and oversight of operating units
- Established corporate policy in Environment, Health and Safety area
- Responsible for permitting new facilities and expansions

- Preformed due diligence reviews of EHS risks for acquisitions
- Audited operating units for EHS and plant performance compliance
- Implemented company-wide metrics for efficiency and environmental performance
- Set up award program for plant performance improvement projects
- Identified external opportunities for potential new business
- Assembled and directed evaluation and negotiation teams

Westinghouse Electric Corporation**September 1981 – December 1993**

Pittsburgh, Pennsylvania

Positions of increasing responsibility and authority, including: Senior Engineer, Pressurized Water Reactor Division Manager, Plant Engineering, Resource Energy Systems Division Principal Engineer, Resource Energy Systems Division

Functional areas of responsibility and experience included:

- Project Management:
 - Planned, contracted and coordinated annual maintenance outages at waste-to-energy power plants. The last outage managed was on schedule and 29% (\$1.4M US) under budget
 - Initiated and led task force efforts to combine the services required at four plants into single, multi-year contracts. Savings of over 40% (over \$2M US) for weld metal overlay services resulted over the next two years
- Engineering:
 - Preformed stress analysis and seismic analysis for pumps and valves, including design and field follow for required upgrades and modifications
 - Developed engineering specifications for mechanical equipment, evaluated bids and selected vendors and verified final design calculations
 - Researched and wrote the first acceptance criteria for loss of resin from a mixed-bed demineralizer into a commercial nuclear primary water system for pressurized water reactors
 - Verified computer code for thermodynamic calorimeter testing of fuel HHV
- Project Management
 - Directed the interface at the plant level with the EPA, PaDER, OSHA, Pa Fish and Game Commission, US Coast Guard, municipal waste water treatment facilities and boiler inspectors in the complex waste-to-energy regulatory environment
 - Assignment as Plant Safety Officer, responsible for implementing OSHA and corporate-required industrial hygiene and safety programs. Assumed lead role in an OSHA audit that resulted in \$0 in fines
 - Presentations to the US Nuclear Regulatory Commission in support of the company's position on compliance issues
- Technical Training
 - Structured, prepared and taught training programs for operations staff at three plants. Course lengths were from 40 hours to six weeks, covering equipment and systems theory and operation
 - Researched and compiled study material for ASME QRO licensing exam
- Proposal Development
 - Performed cost development, encompassing the costs to design, construct, start-up, operate and maintain waste-fired power plant projects with capital costs in the \$100M range
 - Directed the conceptual design efforts for plant proposals, coordinating and reviewing the efforts of the A/E and internal process design team to meet site restrictions and RFP requirements

EDUCATION

- B.S., Engineering Science and Mechanics, Georgia Institute of Technology, 1981
- Graduate courses in Elasticity, Analytical Dynamics, Strength and Fracture, Heat Transfer, Incompressible Flow and Mechanical Vibrations at the University of Pittsburgh

LICENSES AND AWARDS

- Professional Engineer, Province of Ontario
- ASME QRO License for Resource Recovery Facility Operators (lapsed)
- Westinghouse Corporate Engineering Achievement Award, 1985

Exhibit B:

Submitted with the Evidence of Bruce Biewald, Wilson Rickerson,
Geoff Keith, and Susan Shaw

The Effect of Income Tax Status on COMFIT Rates

Resource Class	COMFIT Rate Assuming a Taxable Owner	COMFIT Rate Assuming a Non- Taxable Owner	% Difference	Average
Wind ≤50 kW	\$460	\$444	-3.5%	\$452
Wind >50 kW	\$142	\$136	-4.2%	\$139
Biomass CHP	\$156	\$154	-1.3%	\$155
Run-of-River Hydro	\$138	\$142	2.9%	\$140
In-Steam Tidal	\$698	\$605	-13%	\$652

Notes: for large and small wind, hydro and tidal we have proposed the average as the COMFIT tariff rate. For biomass CHP we have proposed the rate calculated for a taxable entity.

Exhibit C:
Submitted with the Evidence of Bruce Biewald, Wilson Rickerson,
Geoff Keith and Susan Shaw

Assumptions about Capital Structure and Costs in the Tariff Modeling

	Wind ≤50 kW	Wind >50 kW	Hydro	Biomass CHP	Tidal
Capital Structure					
Debt	50%	50%	60%	60%	0%
Equity	50%	50%	40%	40%	100%
Return on Equity					
IRR	13%	13%	13%	13%	15%
Debt Terms					
Amortization Period (years)	10	15	15	15	N/A
Interest Rate	8%	8%	8%	9.5%	N/A
Average DSCR	1.5x	1.5x	1.5x	1.5x	N/A
Up-Front Fee (% of loan value)	1%	1%	1%	1%	N/A
Closing Costs (% of loan value)	5%	5%	5%	5%	N/A

Exhibit D:
Submitted with the Evidence of Bruce Biewald, Wilson Rickerson,
Geoff Keith and Susan Shaw

Interconnection Information Provided by NSPI

1. List of On-Site facilities (costs refer to tables, A, B & C below)

A. For projects greater than 100 kW the typical NSPI facilities on site are as follows:

- 15 or 25 kV Class Recloser
- 10 kVA Distribution transformer (AC supply to recloser control) c/w fused cutout
- 15 or 25 kV class 3 element primary metering Rack w/ 3 CTs and 3 PTs, secondary wiring
- Revenue meter c/w test block and meter base
- Disconnect switches
- Overhead conductor
- Poles, insulators, anchors, pole and line hardware etc.
- Distribution class lightning arrestors

Estimated cost for these facilities (installed): \$82,500 (2011\$)

Range for In-service Projects (Actual): \$45,000 - \$120,000 (2005\$ to 2010\$)

B. For projects greater than 100 kW the typical customer facilities on site are as follows:

- 15 or 25 kV switches
- Distribution Class Lightning Arrestors
- High voltage cable c/w terminations, elbows
- Step up transformer, c/w fuses
- Low voltage cables, c/w terminations
- Concrete transformer pad, grounding
- Poles, insulators, anchors, pole and line hardware etc.
- Underground conduits/ducts as required.

2. For projects less than 50 kW, the typical NSPI facilities required (and therefore the costs) can vary greatly depending on the type and capacity of the generation.

A. Generally for small (less than 10 kW) single phase wind installations there would be minimal NSPI facilities costs, assuming there is already a power supply at the site. The NSPI facilities in this case could include:

- 25 kVA Distribution transformer c/w fused cutout
- Revenue meter and meter base
- Overhead conductor
- Poles, insulators, anchors, pole and line hardware etc.
- Distribution class lightning arrestors

Estimated Cost: \$5000

B. Larger (>20 kW) wind turbines generally are three-phase machines and require additional equipment:

- 3 X 25 kVA Distribution transformers c/w fused cutout
- 3 element revenue meter c/w test block and meter base
- Overhead conductor
- Poles, anchors etc, as required to support equipment
- Distribution class lightning arrestors

Estimated Cost: \$10,000

3. Line Extensions/Upgrade Costs

- Estimated cost for line extensions (installed): \$55,000 per kilometer (2011\$)
- Average for In-service Projects (Table A: Actual): \$54,000 (2005\$ to 2010\$)
- Typical line extension length is closer to 1 km for large installations. Note that the Table A average includes a 10.8 km extension for a single project. If this data point is excluded, the average line extension length is closer to 1 km for larger generator projects, as is the case for Table B and Table C.

- Average Distribution Upgrade Costs:

Table A - In-Service projects	\$	33,462 (Actual)
Table B - Proposed Projects with PPAs	\$	70,209 (Estimated)
Table C - Proposed Projects without PPAs	\$	107,464 (Estimated)

Table A - In-Service projects										
Project #	Connecting at distribution or utilization level?	Net Metered?	Length of line extension (m) required (if any)	Estimated or actual Line Extension Cost	On-site Equipment Costs	Estimated or actual Onsite Costs	Type of system upgrades required (if any)	Estimated or actual cost of system upgrades	Total estimated or actual interconnection costs	Did the project interconnect?
1	Distribution	NO	60	\$ 18,000	-Primary metering -Transfer trip tele-protection system -Switches	\$ 60,000	-Relocate 25kV recloser -Add 70' pole for antenna	\$ 7,000	\$ 85,000	YES
2	Distribution	NO	2500	\$ 94,000	-Recloser -Primary Metering -Switches	\$ 58,000	-Reconductor 2400 m -1 to 3 phase conversion 1000 m	\$ 214,000	\$ 366,000	YES
3	Distribution	NO	10860	\$ 544,000	-Recloser -Primary Metering -Switches	\$ 56,500	None	\$ -	\$ 600,500	YES
4	Distribution	NO	180	\$ 12,500	-Recloser -Primary Metering -Switches	\$ 44,300	-1 to 3 phase conversion 480m	\$ 19,400	\$ 76,200	YES
5	Distribution	NO	360	\$ 21,400	-Recloser -Primary Metering -Switches	\$ 65,400	None	\$ -	\$ 86,800	YES
6	Distribution	NO	60	\$ 7,500	-Recloser -Primary Metering -Switches	\$ 49,300	None	\$ -	\$ 56,800	YES
7	Distribution	NO	600	\$ 28,300	-Recloser -Primary Metering -Switches	\$ 55,600	None	\$ -	\$ 83,900	YES
8	Distribution	NO	55	\$ 6,200	-Recloser -Primary Metering -Switches	\$ 48,500	None	\$ -	\$ 54,700	YES
9	Distribution	NO	300	\$ 15,300	-Recloser -Primary Metering -Switches	\$ 53,800	None	\$ -	\$ 69,100	YES
10	Distribution	NO	750	\$ 42,700	-Recloser -Primary Metering -Switches	\$ 52,100	None	\$ -	\$ 94,800	YES
11	Distribution	NO	2790	\$ 98,100	-Recloser -Primary Metering -Switches	\$ 61,300	1 to 3 phase conversion 4000m	\$ 194,600	\$ 354,000	YES
12	Distribution	NO	3000	\$ 203,500	-Recloser -Primary Metering -Switches -Communication System/SCADA	\$ 119,000	None	\$ -	\$ 322,500	YES
13	Distribution	NO	2000	\$ 180,300	-Recloser -Primary Metering -Switches	\$ 59,000	None	\$ -	\$ 239,300	YES
A. Average for In-Service projects (Actual)			1809	\$ 97,831		\$ 60,215		\$ 33,462	\$ 191,508	

Table B - Proposed Projects with PPAs										
Project #	Connecting at distribution or utilization level?	Net Metered?	Length of line extension (m) required (if any)	Estimated or actual Line Extension Cost	On-site Equipment Costs	Estimated or actual Onsite Costs	Type of system upgrades required (if any)	Estimated or actual cost of system upgrades	Total estimated or actual interconnection costs	Did the project interconnect?
14	Distribution	NO	1400	\$ 77,000	-Recloser -Primary Metering -Switches	\$ 82,500	None	\$ -	\$ 159,500	Pending
15	Distribution	NO	1400	\$ 77,000	-Recloser -Primary Metering -Switches	\$ 82,500	-Reconductor 440 m -1 to 3 phase conversion 4600 m	\$ 116,600	\$ 276,100	Pending
16	Distribution	NO	150	\$ 8,250	-Recloser -Primary Metering -Switches	\$ 82,500	-Reconductor 490 m	\$ 16,200	\$ 106,950	Pending
17	Distribution	NO	1000	\$ 55,000	-Recloser -Primary Metering -Switches	\$ 82,500	-Voltage Conversion -Reconductor 1820 m -1 to 3 phase conversion 1820 m	\$ 154,000	\$ 291,500	Pending
18	Distribution	NO	1230	\$ 67,600	-Recloser -Primary Metering -Switches	\$ 82,500	None	\$ -	\$ 150,100	YES
19	Distribution	NO	2300	\$ 126,500	-Recloser -Primary Metering -Switches	\$ 82,500	-1 to 3 phase conversion 250m	\$ 5,500	\$ 214,500	YES
20	Distribution	NO	1800	\$ 99,000	-Recloser -Primary Metering -Switches	\$ 82,500	-Reconductor 4200 m -1 to 3 phase conversion 6790 m	\$ 288,000	\$ 469,500	Pending
21	Distribution	NO	500	\$ 27,500	-Recloser -Primary Metering -Switches	\$ 82,500	-Reconductor 360 m -1 to 3 phase conversion 360m	\$ 20,000	\$ 130,000	Pending
22	Distribution	NO	600	\$ 33,000	-Recloser -Primary Metering -Switches	\$ 82,500	None	\$ -	\$ 115,500	Pending
23	Distribution	NO	900	\$ 49,500	-Recloser -Primary Metering -Switches	\$ 82,500	-Reconductor 3120 m -1 to 3 phase conversion 3120 m	\$ 172,000	\$ 304,000	Pending
24	Distribution	NO	160	\$ 8,800	-Recloser -Primary Metering -Switches	\$ 82,500	None	\$ -	\$ 91,300	Pending
B. Average for Proposed Projects with PPAs (Estimated)			1040	\$ 57,195		\$ 82,500		\$ 70,209	\$ 209,905	

Table C - Proposed Projects without PPAs										
Project #	Connecting at distribution or utilization level?	Net Metered?	Length of line extension (m) required (if any)	Estimated or actual Line Extension Cost	On-site Equipment Costs	Estimated or actual Onsite Costs	Type of system upgrades required (if any)	Estimated or actual cost of system upgrades	Total estimated or actual interconnection costs	Did the project interconnect?
24	Distribution	NO	2150	\$ 118,250	-Recloser -Primary Metering -Switches	\$ 82,100	-Reconductor 3240 m -1 to 3 phase conversion 1400 m	\$ 137,700	\$ 338,050	NO
25	Distribution	NO	0	\$ -	-Recloser -Primary Metering -Switches	\$ 82,500	-Reconductor 1070 m -1 to 3 phase conversion 570 m	\$ 47,900	\$ 130,400	NO
26	Distribution	NO	400	\$ 22,000	-Recloser -Primary Metering -Switches	\$ 82,500	None	\$ -	\$ 104,500	NO
27	Distribution	NO	200	\$ 11,000	-Recloser -Primary Metering -Switches	\$ 82,500	None	\$ -	\$ 93,500	NO
28	Distribution	NO	2500	\$ 137,500	-Recloser -Primary Metering -Switches	\$ 82,500	-Reconductor 6500 m	\$ 214,500	\$ 434,500	NO
29	Distribution	NO	700	\$ 38,500	-Recloser -Primary Metering -Switches	\$ 82,500	None	\$ -	\$ 121,000	NO
30	Distribution	NO	100	\$ 5,500	-Recloser -Primary Metering -Switches	\$ 82,500	-1 to 3 phase conversion 710m	\$ 15,600	\$ 103,600	NO
31	Distribution	NO	500	\$ 27,500	-Recloser -Primary Metering -Switches	\$ 82,500	-1 to 3 phase conversion 11150 m -2 to 3 phase conversion 8230 m	\$ 400,100	\$ 510,100	NO
32	Distribution	NO	500	\$ 27,500	-Recloser -Primary Metering -Switches	\$ 82,500	-Reconductor 360 m -1 to 3 phase conversion 360m	\$ 19,800	\$ 129,800	NO
33	Distribution	NO	0	\$ -	-Recloser -Primary Metering -Switches	\$ 5,000	None	\$ -	\$ 5,000	NO
34	Distribution	NO	3000	\$ 165,000	-Recloser -Primary Metering -Switches	\$ 82,500	None	\$ -	\$ 247,500	NO
35	Distribution	NO	2000	\$ 110,000	-Recloser -Primary Metering -Switches	\$ 82,500	None	\$ -	\$ 192,500	NO
36	Distribution	NO	1800	\$ 99,000	-Recloser -Primary Metering -Switches	\$ 82,500	None	\$ -	\$ 181,500	NO
37	Distribution	NO	1300	\$ 71,500	-Recloser -Primary Metering -Switches	\$ 82,500	-Reconductor 560 m -1 to 3 phase conversion 560 m -2 to 3 phase conversion 2530 m	\$ 64,200	\$ 218,200	NO
38	Distribution	NO	1300	\$ 71,500	-Recloser -Primary Metering -Switches	\$ 82,500	-Reconductor 360 m -1 to 3 phase conversion 360m	\$ 308,500	\$ 462,500	NO
39	Distribution	NO	100	\$ 5,500	-Recloser -Primary Metering -Switches	\$ 82,500	None	\$ -	\$ 88,000	NO
40	Distribution	NO	500	\$ 27,500	-Recloser -Primary Metering -Switches	\$ 82,500	-Voltage Conversion 805 kVA -Reconductor 13800 m -1 to 3 phase conversion 4200 m	\$ 857,000	\$ 967,000	NO
41	Distribution	NO	750	\$ 41,250	-Recloser -Primary Metering -Switches	\$ 82,500	None	\$ -	\$ 123,750	NO

Table C - Proposed Projects without PPAs (Continued)										
Project #	Connecting at distribution or utilization level?	Net Metered?	Length of line extension (m) required (if	Estimated or actual Line Extension Cost	On-site Equipment Costs	Estimated or actual Onsite Costs	Type of system upgrades required (if any)	Estimated or actual cost of system upgrades	Total estimated or actual interconnection costs	Did the project interconnect?
42	Distribution	NO	1000	\$ 55,000	-Recloser -Primary Metering -Switches	\$ 82,500	Contribution to Contributed Line	\$ 100,000	\$ 237,500	NO
43	Distribution	NO	80	\$ 4,400	-Recloser -Primary Metering -Switches	\$ 82,500	None	\$ -	\$ 86,900	NO
44	Distribution	NO	500	\$ 27,500	-Recloser -Primary Metering -Switches	\$ 82,500	-Reconductor 1710 m -1 to 3 phase conversion 5060 m	\$ 168,000	\$ 278,000	NO
45	Distribution	NO	1500	\$ 82,500	-Recloser -Primary Metering -Switches	\$ 82,500	None	\$ -	\$ 165,000	NO
46	Distribution	NO	100	\$ 5,500	-Recloser -Primary Metering -Switches	\$ 82,500	None	\$ -	\$ 88,000	NO
47	Distribution	NO	230	\$ 12,650	-Recloser -Primary Metering -Switches	\$ 82,500	None	\$ -	\$ 95,150	NO
48	Distribution	NO	300	\$ 16,500	-Recloser -Primary Metering -Switches	\$ 82,500	-Reconductor 1710 m -1 to 3 phase conversion 350 m	\$ 22,000	\$ 121,000	NO
49	Distribution	NO	750	\$ 41,250	-Recloser -Primary Metering -Switches	\$ 82,500	-Reconductor 7380 m -1 to 3 phase conversion 7830 m	\$ 406,000	\$ 529,750	NO
50	Distribution	NO	750	\$ 41,250	-Recloser -Primary Metering -Switches	\$ 82,500	None	\$ -	\$ 123,750	NO
51	Distribution	NO	1170	\$ 64,350	-Recloser -Primary Metering -Switches	\$ 82,500	-Reconductor 1540 m -1 to 3 phase conversion 550 m	\$ 63,000	\$ 209,850	NO
52	Distribution	NO	1170	\$ 64,350	-Recloser -Primary Metering -Switches	\$ 82,500	-Reconductor 1540 m -1 to 3 phase conversion 550 m	\$ 63,000	\$ 209,850	NO
53	Distribution	NO	0	\$ -	-Recloser -Primary Metering -Switches	\$ 82,500	-1 to 3 phase conversion 8710 m	\$ 192,000	\$ 274,500	NO
54	Distribution	NO	0	\$ -	-Recloser -Primary Metering -Switches	\$ 82,500	-Reconductor 2850 m -1 to 3 phase conversion 9050 m -Contribution to Contributed Line	\$ 343,000	\$ 425,500	NO
55	Distribution	NO	500	\$ 27,500	-Recloser -Primary Metering -Switches	\$ 82,500	None	\$ -	\$ 110,000	NO
56	Distribution	NO	300	\$ 16,500	-Recloser -Primary Metering -Switches	\$ 82,500	-Reconductor 2260 m -1 to 3 phase conversion 2260 m	\$ 124,000	\$ 223,000	NO
C. Average for proposed projects W/O PPAs (Estimated)			792	\$ 43,583		\$ 80,139		\$ 107,464	\$ 231,186	

Summary of Interconnection Data Provided by NSPI

			Ave. Length of line extension (m)	Ave. Estimated or actual Line Extension Cost	Ave. Estimated or actual Onsite Costs	Ave Estimated or actual cost of system upgrades	Ave. Total estimated or actual interconnection costs
A. Average for In-Service projects (Actual)			1809	\$ 97,831	\$ 60,215	\$ 33,462	\$ 191,508
B. Average for Proposed Projects with PPAs (Estimated)			1040	\$ 57,195	\$ 82,500	\$ 70,209	\$ 209,905
Average for "Successful" Projects (A and B)			1456	\$ 79,206	\$ 70,429	\$ 50,304	\$ 199,940
C. Average for proposed projects W/O PPAs (Estimated)			792	\$ 43,582	\$ 80,139	\$ 107,464	\$ 231,185
Overall Average (A, B and C)			1072	\$ 58,582	\$ 76,051	\$ 83,396	\$ 218,030

Exhibit E:

Submitted with the Evidence of Bruce Biewald, Wilson Rickerson,
Geoff Keith and Susan Shaw

Interconnection Costs Included for in the Tariff Modeling (\$2012)

	Wind ≤50 kW	Wind >50 kW	Biomass CHP	Hydro	Tidal
Studies	\$10,200	\$7,600	\$7,600	\$7,600	\$7,600
NSPI Equip.	\$3,100	\$84,100	\$84,100	\$84,100	\$84,100
Customer Equip. (Transformer)	\$0	\$0	\$102,000	\$76,400	\$51,000
Customer Equip. (Other)	\$0	\$5,100	\$5,100	\$5,100	\$5,100
Line Extension	\$0	\$112,000	\$0	\$112,000	\$112,000
Total	\$13,300	\$209,000	\$199,000	\$285,000	\$260,000

Notes: Totals have been rounded.

Exhibit F:
Submitted with the Evidence of Bruce Biewald, Wilson Rickerson,
Geoff Keith and Susan Shaw

Cost and Performance Assumptions in the Tariff Modeling

The table below shows summary information about the calculations on which our proposed tariffs are based. Tables 2 through 6 show more detailed input assumptions for each resource class.

Table 1. Summary of Key Information from Modeling (\$2012)

	Wind ≤50 kW	Wind >50 kW	Biomass CHP	Hydro	Tidal
Project Size (MW)	0.05	1.5	2.1	1	0.5
Capital Cost (\$)	\$321,674	\$3,779,553	\$8,048,456	\$4,446,592	\$5,039,368
Capital Cost (\$/kW)	\$6,427	\$2,520	\$3,926	\$4,447	\$10,079
Routine O&M (\$, year 1)	\$1,642	\$55,000	\$93,667	\$50,000	\$75,000
Major Maintenance	in routine O&M	in routine O&M	\$356,720	in routine O&M	\$62,500
Major Maint. Period (years)	in routine O&M	in routine O&M	11	in routine O&M	6
Fuel Cost (\$, year 1)	0	0	\$702,693	0	0
Capacity Factor (%)	23	31	85	55	37
Generation (MWh)	101	4,073	12,636	4,818	1,621
Proposed COMFIT Rate (\$/MWh)	\$452	\$139	\$156	\$140	\$652
Year 1 Revenues	\$46,611	\$582,246	\$1,991,738	\$670,388	\$1,133,349

Notes: the capital costs presented here for biomass CHP are the costs of the CHP Scenario less the Steam-Only Scenario as shown in Table 4 below. For all technologies except biomass CHP, the proposed COMFIT rate is the average of the rates calculated assuming a taxable and non taxable owner. For biomass CHP we have proposed the rate calculated assuming a taxable owner. All information in this exhibit, except the proposed COMFIT rates in Table 1, is taken from the calculations assuming a taxable owner.

Table 2. Cost and Performance Assumptions for Wind ≤50 kW (\$2012)

Assumption	Value	Calculation
Project Costs		
Development	\$0	Included in Equipment & Installation
Equipment & Installation	\$268,000	Input assumption
Interconnection	\$13,300	Input assumption (see Exhibit F)
Maintenance Reserve	\$821	One half of year-one O&M
Working Capital Reserve	\$1,826	One half of year-one expenses
Debt Service Reserve	\$11,982	One half of year-one debt service
Debt Costs and Fees	\$9,648	1% up-front fee and closing costs equal to 5% of the loan value
Equity Costs and Fees	\$6,720	4% of the equity value
Interest During Construction	\$9,377	(Installed Cost) × (Construction Months/2) × (10%/12)
Total Project Cost	\$321,674	Calculated
Total Project Cost (\$/kW)	\$6,433	Calculated
Routine O&M (\$/yr)	\$1,642	1.63 cents per kWh, escalates at inflation
General & Administrative	\$0	Input assumption, escalates with inflation
Major Maintenance	\$0	Included in Routine O&M
Major Maint. Period (years)	N/A	Included in Routine O&M
Insurance (\$/yr)	\$2,010	0.75% of installed costs, escalates at inflation
Land Lease (\$/yr)	\$0	Input assumption, escalates with inflation
Royalty Payment (\$/yr)	\$0	Input assumption, escalates with inflation
Residual Value (\$)	\$0	Input assumption
Decommissioning Cost (\$)	\$0	Input assumption
Project Performance		
Generator Capacity (MW)	0.05	Input assumption
Net Capacity Factor (%)	23	Input assumption
Taxes		
Assessed Value (%)	N/A	Input assumption
Property Tax Rate (%)	0	Input assumption
Federal Income Tax Rate (%)	15	Input assumption
Provincial Income Tax Rate (%)	4.5/16	Input assumption (first \$400,000 is taxed at 4.5%, revenue above that at 16%)

Table 3. Cost and Performance Assumptions for Wind >50 kW (\$2012)

Assumption	Value	Calculation
Project Costs		
Development	\$500,000	Input assumption
Equipment & Installation	\$2,565,000	Input assumption
Interconnection	\$209,000	Input assumption (see Exhibit F)
Maintenance Reserve	\$27,500	One half of year-one O&M
Working Capital Reserve	\$40,067	One half of year-one expenses
Debt Service Reserve	\$110,346	One half of year-one debt service
Debt Costs and Fees	\$113,340	1% up-front fee and closing costs equal to 5% of the loan value
Equity Costs and Fees	\$75,600	4% of the equity value
Interest During Construction	\$138,700	(Installed Cost) × (Construction Months/2) × (10%/12)
Total Project Cost	\$3,779,553	Calculated
Total Project Cost (\$/kW)	\$2,520	Calculated
Routine O&M (\$/yr)	\$55,000	Input assumption, escalates at inflation
General & Administrative	\$1,000	Input assumption, escalates at inflation
Major Maintenance	\$0	Included in Routine O&M
Major Maint. Period (years)	N/A	Included in Routine O&M
Insurance (\$/yr)	\$7,695	0.3% of installed costs, escalates at inflation
Land Lease (\$/yr)	\$14,400	2.5% of revenues, escalates with inflation
Royalty Payment (\$/yr)	\$0	Input assumption, escalates with inflation
Residual Value (\$)	\$0	Input assumption
Decommissioning Cost (\$)	\$0	Input assumption
Project Performance		
Generator Capacity (MW)	1.5	Input assumption
Net Capacity Factor (%)	31	Input assumption
Taxes		
Assessed Value (%)	20	Input assumption
Property Tax Rate (%)	0.4	Input assumption
Federal Income Tax Rate (%)	15	Input assumption
Provincial Income Tax Rate (%)	4.5/16	Input assumption (first \$400,000 is taxed at 4.5%, revenue above that at 16%)

Table 4. Cost and Performance Assumptions for Biomass CHP (\$2012)
Existing Boiler Replaced in Year 10 in Steam-Only Scenario

Assumption	Steam-Only Scenario	CHP Scenario	Calculation
Project Costs			
Project development	\$42,134	\$280,280	Input assumption
Boiler installed cost (\$)	\$1,685,370	\$3,057,600	Input assumption
Turbine installed cost (\$)	\$0	\$2,894,528	Input assumption
Emission controls	\$252,806	\$305,760	Input assumption
Condenser/Cooling Tower	\$0	\$1,630,720	Input assumption
Equipment and Installation (\$)	\$1,938,176	\$7,888,608	Calculation (does not include development)
Interconnection	\$0	\$199,000	Input assumption (see Exhibit F)
Maintenance Reserve	\$65,279	\$86,632	One half of year-one O&M
Working Capital Reserve	\$536,049	\$949,934	One half of year-one expenses
Debt Service Reserve	\$213,498	\$777,905	One half of year-one debt service
Debt Costs and Fees	\$109,646	\$399,506	1% up-front fee and closing costs equal to 5% of the loan value
Equity Costs and Fees	\$48,718	\$177,545	4% of the equity value
Interest During Construction	\$91,371	\$332,922	(Installed Cost) × (Construction Months/2) × (10%/12)
Total Project Cost	\$3,044,134	\$11,092,590	Calculated
Total Project Cost (\$/kW)	N/A	\$5,411	Calculated
Routine Maintenance (\$/yr)	\$436,317	\$529,984	Input assumption, escalates at inflation
General & Administrative	\$0	\$0	Input assumption, escalates at inflation
10-Year Boiler Overhaul (\$)	\$0	\$152,880	Input assumption
10-Year Boiler Overhaul (\$)	\$0	\$203,840	Input assumption
Insurance (\$/yr)	\$9,691	\$39,443	0.5% of installed costs, escalates at inflation
Land Lease (\$/yr)	\$0	\$0	Input assumption, escalates with inflation
Residual Value (\$)	\$0	\$0	Input assumption
Decommissioning Cost (\$)	\$0	\$0	Input assumption
Project Performance			
Generator Capacity (MW)	N/A	2.05	Input assumption
Net Capacity Factor (%)	N/A	85	Input assumption
Taxes			
Assessed Value (%)	N/A	N/A	Property taxes calculated on net basis in the model
Property Tax Rate (%)	N/A	N/A	Input assumption
Federal Income Tax Rate (%)	15	15	Input assumption
Provincial Income Tax Rate (%)	4.5/16	4.5/16	Input assumption (first \$400,000 is taxed at 4.5%, above that at 16%)

Table 5. Cost and Performance Assumptions for Hydro (\$2012)

Assumption	Value	Calculation
Project Costs		
Development	\$0	Included in Equipment & Installation
Equipment & Installation	\$3,900,000	Input assumption
Interconnection	\$285,000	Input assumption (see Exhibit F)
Maintenance Reserve	\$25,000	One half of year-one O&M
Working Capital Reserve	\$80,625	One half of year-one expenses
Debt Service Reserve	\$155,967	One half of year-one debt service
Debt Costs and Fees	\$0	Included in Equipment & Installation
Equity Costs and Fees	\$0	Included in Equipment & Installation
Interest During Construction	\$0	Included in Equipment & Installation
Total Project Cost	\$4,446,592	Calculated
Total Project Cost (\$/kW)	\$4,447	Calculated
Routine O&M (\$/yr)	\$50,000	Input assumption, escalates with inflation
General & Administrative	\$1,000	Input assumption, escalates with inflation
Major Maintenance	\$0	Included in Routine O&M
Major Maint. Period (years)	\$0	Included in Routine O&M
Insurance (\$/yr)	\$39,000	1% of installed costs, escalates at inflation
Land Lease (\$/yr)	\$2,500	(Access lease) Input assumption, escalates with inflation
Royalty Payment (\$/yr)	\$500	Input assumption, escalates with inflation
Residual Value (\$)	\$1,170,000	Calculated net book value
Decommissioning Cost (\$)	\$0	Input assumption
Project Performance		
Generator Capacity (MW)	1	Input assumption
Net Capacity Factor (%)	55	Input assumption
Taxes		
Assessed Value (%)	50	Input assumption
Property Tax Rate (%)	3.5	Input assumption
Federal Income Tax Rate (%)	15	Input assumption
Provincial Income Tax Rate (%)	4.5/16	Input assumption (first \$400,000 is taxed at 4.5%, revenue above that at 16%)

Table 6. Cost and Performance Assumptions for In-Stream Tidal (\$2012)

Assumption	Value	Calculation
Project Costs		
Development	\$950,000	Input assumption
Equipment & Installation	\$3,335,000	Input assumption
Interconnection	\$260,000	Input assumption (see Exhibit F)
Maintenance Reserve	\$37,500	One half of year-one O&M
Working Capital Reserve	\$75,518	One half of year-one expenses
Debt Service Reserve	\$0	One half of year-one debt service
Debt Costs and Fees	\$0	1% up-front fee and closing costs equal to 5% of the loan value
Equity Costs and Fees	\$201,600	4% of the equity value
Interest During Construction	\$179,750	(Installed Cost) × (Construction Months/2) × (10%/12)
Total Project Cost	\$5,039,368	Calculated
Total Project Cost (\$/kW)	\$10,079	Calculated
Routine O&M (\$/yr)	\$75,000	Input assumption, escalates with inflation
General & Administrative	\$1,000	Input assumption, escalates with inflation
Major Maintenance	\$62,500	Input assumption
Major Maint. Period (years)	6	Input assumption
Insurance (\$/yr)	\$66,700	2% of installed costs, escalates at inflation
Land Lease (\$/yr)	\$2,500	(Access lease) Input assumption, escalates with inflation
Royalty Payment (\$/yr)	\$0	Input assumption, escalates with inflation
Residual Value (\$)	\$0	Input assumption
Decommissioning Cost (\$)	\$0	Input assumption
Project Performance		
Generator Capacity (MW)	0.5	Input assumption
Net Capacity Factor (%)	37	Input assumption
Taxes		
Assessed Value (%)	5	Input assumption (assuming that the vast majority of installed costs are offshore)
Property Tax Rate (%)	3.5	Input assumption
Federal Income Tax Rate (%)	15	Input assumption
Provincial Income Tax Rate (%)	4.5/16	Input assumption (first \$400,000 is taxed at 4.5%, revenue above that at 16%)

Exhibit G:
Submitted with the Evidence of Bruce Biewald, Wilson Rickerson,
Geoff Keith and Susan Shaw

Information Requested from Sawmills

Information Requested by Synapse about Steam Production at Nova Scotia Sawmills

Synapse Energy Economics has been retained by the Nova Scotia Utility and Review Board (Board) to research and propose rates for community based feed-in tariffs (COMFITs). To inform our thinking about the cost of developing a biomass CHP project in the Province, we request that you provide the following information about your company's current steam production and needs. If you consider this information to be confidential, please indicate this in the space provided. Synapse will not share confidential information with anyone outside of our project team, nor will we release any data from which specific confidential information could be deduced.

Please return this form to Geoff Keith at: gkeith@synapse-energy.com. Please provide this information as soon as possible. Synapse must file its final proposed tariffs on February 28th, and information received after February 16th will be of limited use. If you have questions regarding this request, please call Geoff Keith at Synapse at: 617-661-3248 x249.

Company name and facility name:

Person providing data:

Is this information confidential?

Do you currently operate a biomass-fired boiler?

If you do not have a boiler, do you operate an electric kiln?

If you have a boiler:

Where is the boiler (town or municipality)?

How old is this boiler?

What is the boiler's maximum capacity rating (lbs/hr)?

What is the boiler's maximum pressure rating (psi)?

*What is the typical inlet pressure of steam to the kiln?

Does the plant have a pressure reduction valve between the boiler and the kilns?

*If so, what are the inlet and outlet pressures and the flow rate of this valve?

*At what pressure do you typically operate the boiler now?

*At what pressure are the boiler's safety release valves set?

What is the original maximum continuous operating pressure of the boiler?

**For these questions, provide a range if there is not a single typical value.*

Please add below anything else you would like us to know about your steam production or needs.

Exhibit H:

Submitted with the Evidence of Bruce Biewald, Wilson Rickerson,
Geoff Keith, and Susan Shaw

The Effect of Steam Demand on the CHP Rate (\$2012)

Steam Capacity Factor	20%	30%	40%	50%	60%
IRR at \$156/MWh COMFIT Rate	6.0%	7.9%	9.6%	11.3%	13%
COMFIT Rate Needed for 13% IRR	\$172	\$168	\$164	\$161	\$156
Overall Plant Efficiency	29%	34%	40%	46%	52%

Notes: these numbers were calculated assuming a condensing turbine project at a facility with roughly 10 years of life left on its existing boiler. The steam capacity factor is the percentage of annual hours that the system provides steam to the steam host. The IRR is the return on equity calculated in by model at a given COMFIT electricity rate.

Nova Scotia COMFIT Model

Assumptions		Notes:
General Inflation Factor (revenue and expenses)	1.92%	From NSPI 2009 IRP Update
Capital Costs (Uses of Funds)		
Development	\$0	
Equipment & Installation	\$268,000	
Interconnection	\$13,300	
Reserves		
Up-Front Maintenance	\$821	(Half of year-one O&M)
Working Capital	\$1,826	(Half of year-one expenses)
Debt Service Reserve	\$11,975	(Half of year-one debt service.)
Financing		
Debt Closing Costs & Fees	\$9,642	(Summed from below)
Equity Closing Costs & Fees	\$6,424	(Estimated as 4% of equity)
Interest During Construction	\$9,377	
Total Project Cost	\$321,364	
Total Project Cost (\$/kW)	\$6,427	
Initial Reserve Account Sizing		
Upfront Maintenance (months of Year 1 O&M)	6	
Working Capital (months of Year 1 OPEX)	6	
Debt Service Reserve (months of P&I)	6	
Capital Structure (Sources of Funds)		
Amount (\$)		
Grants (net value)	0	
Debt	160,700	
Equity	160,664	
Total Sources of Funds	321,364	
Amount (%)		
Grants	0.0%	
Debt	50.0%	
Equity	50.0%	
Total Sources of Funds	100.0%	
Grants:		
State and Federal Incentives	0	
State/Provincial Tax 1	0	
State/Provincial Tax 2	0	
Federal tax	0	
Net Value of Grants	0	
Debt Terms		
Amount	160,700	(Based on target debt/equity ratio)
Amortization period	10	
Interest Rate	8.00%	
Up-Front Fee (%)	1.00%	
Up-Front Fee (\$)	1,607	
Closing Costs	8,035	(5% of loan value)
Tax Depreciation Allocation		
% of Total Project Cost		
30% Double Declining	0.0%	95% of installed cost
50% Double Declining	79.2%	
20-yr SL	0.0%	
40-yr SL	0.0%	
Other	0.0%	
Non-Depreciable	20.78%	
Total	100.0%	
Amount Allocated		
30% Double Declining	0	
50% Double Declining	254,600	
20-yr SL	0	
40-yr SL	0	
Other	0	
Non-Depreciable	66,764	
Total	321,364	
Year One Depreciation		
Year One Percent	25.0%	(Based on the "half year rule")
Year One Amount	63,650	

Small Wind (50 kW and smaller)

Assumptions Worksheet: All

Assumptions:		Notes:
Operating Inputs		
Net Generator Capacity (MW)	0.05	
Energy Production:		
Net Capacity Factor	23%	Net of plant availability and other loss factors
Net Output in MWhs	101	
Annual Operating Expenses		
Annual Fuel Cost		
Fuel Required per Year (mmBtu)	0	
Initial year Fuel Price (\$/mmBtu)	0	
Routine O&M (expensed)	1,642	Escalates at inflation.
Site Maintenance	0	Escalates at inflation.
General & Administrative	0	Escalates at inflation.
Insurance	2,010	Escalates at inflation.
Land Lease	0	Escalates at inflation.
Other	0	Escalates at inflation.
Property Tax		
Project hard costs less interconnection	268,000	
Assessed Value (%)	0.00%	
Assessed Value (\$)	0	
Annual Decline in Assessed Value	0.00%	
Assessed Value Minimum %	0.00%	
Property Tax Rate	0.00%	Based on Wind Turbine Facilities Municipal Taxation Act
Revenue Assumptions		
Levelized Energy Price (\$/MWh)	459.90	
% of Levelized Rate Escalating @ Infl.	0.0%	
Other Revenues (increases with inflation)	0	
Return Metrics		
20-year Equity IRR		
Pre-Tax	13.93%	
After-Tax	13.00%	
Average Debt Service Coverage Ratio	1.78	
Minimum Debt Service Coverage Ratio	1.77	
Minimum Annual After-Tax Equity Net Benefits	10,962	Includes tax benefit/(liability)
Tax Rates:		
Federal Income Tax	15.0%	
State/Provincial Income Tax		
Small Business Tax Rate		
Applicable Income (less than X)	400,000	
Small Business Tax Rate	4.5%	
Corporate rate (income greater than X)	16.0%	
Major Maintenance		
Replacement Occurs Every X Years	5	
Cost of Replacement (Year 0 Dollars)	0	Included in the cost of Routine O&M.
	50% Double	
	Declining	
Tax Depreciation Classification of Spending	30-yr SL	
Book Depreciation Classification of Spending		
Residual Value		
Residual Value (Net Book Value)	0	
Book Depreciation Classifications		
20-yr SL	100.0%	
30-yr SL	0.0%	
37-yr SL	0.0%	
40-yr SL	0.0%	
Non-Depreciable	0.00%	
Total	100.0%	
Amount Allocated		
20-yr SL	321,364	
30-yr SL	0	
37-yr SL	0	
40-yr SL	0	
Non-Depreciable	0	
Total	321,364	

Synapse Exhibit I

Operating Year		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Generation (MWh)		101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101
Partial Income Statement																						
Revenue																						
Standard Offer Price (\$/MWh)																						
Fixed Price Component	100%	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90
Escalating Price Component	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Standard Offer Price		459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90	459.90
Revenues From Energy Production		46,330	46,330	46,330	46,330	46,330	46,330	46,330	46,330	46,330	46,330	46,330	46,330	46,330	46,330	46,330	46,330	46,330	46,330	46,330	46,330	46,330
Other Revenues		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Revenue		281	281	281	281	281	281	281	281	281	281	281	51	51	51	51	51	51	51	51	51	51
Total Revenue		46,611	46,611	46,611	46,611	46,611	46,611	46,611	46,611	46,611	46,611	46,611	46,381	46,381	46,381	46,381	46,381	46,381	46,381	46,381	46,381	46,381
Expenses																						
Fuel Cost		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O&M		(1,642)	(1,674)	(1,706)	(1,738)	(1,772)	(1,806)	(1,841)	(1,876)	(1,912)	(1,949)	(1,986)	(2,024)	(2,063)	(2,103)	(2,143)	(2,184)	(2,226)	(2,269)	(2,312)	(2,357)	
Site Maintenance		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
G&A		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Insurance		(2,010)	(2,049)	(2,088)	(2,128)	(2,169)	(2,211)	(2,253)	(2,296)	(2,340)	(2,385)	(2,431)	(2,478)	(2,525)	(2,574)	(2,623)	(2,674)	(2,725)	(2,777)	(2,831)	(2,885)	
Land Lease		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Property tax		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total		(3,652)	(3,722)	(3,794)	(3,866)	(3,941)	(4,016)	(4,093)	(4,172)	(4,252)	(4,334)	(4,417)	(4,502)	(4,588)	(4,676)	(4,766)	(4,858)	(4,951)	(5,046)	(5,143)	(5,242)	
EBITDA		42,959	42,889	42,817	42,745	42,670	42,595	42,518	42,439	42,359	42,277	41,964	41,879	41,793	41,705	41,615	41,523	41,430	41,335	41,238	41,140	
Equity Return																						
Cash																						
EBITDA		42,959	42,889	42,817	42,745	42,670	42,595	42,518	42,439	42,359	42,277	41,964	41,879	41,793	41,705	41,615	41,523	41,430	41,335	41,238	41,140	
Plus: Release of Debt Service Reserve		0	0	0	0	0	0	0	0	0	11,975	0	0	0	0	0	0	0	0	0	0	0
Plus: Release of WC & Up-Front Maint Reserves		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,647	
Plus: Release of Major Maintenance Reserves		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus: Residual Value		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less: Major Maintenance Spending		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less: Major Maintenance Reserve Funding		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less: Principal		(11,093)	(11,980)	(12,939)	(13,974)	(15,092)	(16,299)	(17,603)	(19,012)	(20,532)	(22,175)	0	0	0	0	0	0	0	0	0	0	0
Less: Interest		(12,856)	(11,969)	(11,010)	(9,975)	(8,857)	(7,650)	(6,346)	(4,938)	(3,417)	(1,774)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Cash		19,010	18,940	18,868	18,796	18,721	18,646	18,569	18,490	18,410	30,303	41,964	41,879	41,793	41,705	41,615	41,523	41,430	41,335	41,238	43,787	
Equity Investment		(160,664)																				
Total Pre-Tax Equity Return		(160,664)	19,010	18,940	18,868	18,796	18,721	18,646	18,569	18,490	18,410	30,303	41,964	41,879	41,793	41,705	41,615	41,523	41,430	41,335	41,238	43,787
Pre-Tax Internal Rate of Return		13.93%																				
Taxable Income Benefit/(Liability)																						
EBITDA		42,959	42,889	42,817	42,745	42,670	42,595	42,518	42,439	42,359	42,277	41,964	41,879	41,793	41,705	41,615	41,523	41,430	41,335	41,238	41,140	
Less: Interest		(12,856)	(11,969)	(11,010)	(9,975)	(8,857)	(7,650)	(6,346)	(4,938)	(3,417)	(1,774)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Less: Tax Depreciation		(63,650)	(95,475)	(47,738)	(23,869)	(11,934)	(5,967)	(2,984)	(1,492)	(746)	(373)	(186)	(93)	(47)	(23)	(12)	(6)	(3)	(1)	(1)	(0)	
Taxable Income/(Loss)		(33,547)	(64,555)	(15,930)	8,901	21,879	28,978	33,188	36,010	38,196	40,130	41,778	41,786	41,746	41,681	41,603	41,518	41,427	41,334	41,238	41,139	
Tax Benefit/(Liability)																						
State/Provincial 1		1,510	2,905	717	(401)	(985)	(1,304)	(1,493)	(1,620)	(1,719)	(1,806)	(1,880)	(1,880)	(1,879)	(1,876)	(1,872)	(1,868)	(1,864)	(1,860)	(1,856)	(1,851)	
State/Provincial 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Federal		5,032	9,683	2,390	(1,335)	(3,282)	(4,347)	(4,978)	(5,401)	(5,729)	(6,020)	(6,267)	(6,268)	(6,262)	(6,252)	(6,240)	(6,228)	(6,214)	(6,200)	(6,186)	(6,171)	
Total Tax Benefit/(Liability)		6,542	12,588	3,106	(1,736)	(4,266)	(5,651)	(6,472)	(7,022)	(7,448)	(7,825)	(8,147)	(8,148)	(8,141)	(8,128)	(8,113)	(8,096)	(8,078)	(8,060)	(8,041)	(8,022)	
Equity Investment		(160,664)																				
Total After-Tax Equity Return		(160,664)	25,552	31,528	21,975	17,060	14,455	12,995	12,097	11,468	10,962	22,477	33,817	33,731	33,652	33,577	33,502	33,428	33,352	33,275	33,197	35,764
After-Tax Internal Rate of Return		13.00%																				

Operating Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Calendar Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Tax Depreciation																					
Calendar Year Depreciation per Classification (%)																					
30% Double Declining		30.00%	21.00%	14.70%	10.29%	7.20%	5.04%	3.53%	2.47%	1.73%	1.21%	0.85%	0.59%	0.42%	0.29%	0.20%	0.14%	0.10%	0.07%	0.05%	0.03%
50% Double Declining		50.00%	25.00%	12.50%	6.25%	3.13%	1.56%	0.78%	0.39%	0.20%	0.10%	0.05%	0.02%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20-yr SL		2.50%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
40-yr SL		1.25%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Other		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Calendar Year Depreciation per Classification (\$)																					
Year One Capital Cost Allocation	63,650	63,650	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30% Double Declining	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
50% Double Declining	190,950	0	95,475	47,738	23,869	11,934	5,967	2,984	1,492	746	373	186	93	47	23	12	6	3	1	1	0
20-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Major Maintenance	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Annual Depreciation	254,600	63,650	95,475	47,738	23,869	11,934	5,967	2,984	1,492	746	373	186	93	47	23	12	6	3	1	1	0
Major Maintenance																					
Timing of Spending																					
Occurrence 1		0	0	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Occurrence 2		0	0	0	0	0	0	0	0	0	1	2	3	4	5	6	7	8	9	10	11
Occurrence 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	3	4	5	6
Occurrence 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Depreciation Classification																					
Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Depreciation Schedule	0.00%	50.00%	25.00%	12.50%	6.25%	3.13%	1.56%	0.78%	0.39%	0.20%	0.10%	0.05%	0.02%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Depreciation Expense																					
		Expense		Depreciation Amount																	
Occurrence 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Operating Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Calendar Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030

tax Depreciation

Book Depreciation																					
Calendar Year Depreciation per Classification (%)																					
20-yr SL		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
30-yr SL		3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
37-yr SL		2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%
40-yr SL		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%

Calendar Year Depreciation per Classification (\$)																					
20-yr SL	321,364	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068
30-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Major Maintenance		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Annual Depreciation	321,364	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068	16,068

Major Maintenance																					
Timing of Spending																					
Occurrence 1		0	0	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Occurrence 2		0	0	0	0	0	0	0	0	0	1	2	3	4	5	6	7	8	9	10	11
Occurrence 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	3	4	5	6
Occurrence 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1

Depreciation Classification	30-yr SL																				
Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Depreciation Schedule	0.00%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%

Depreciation Expense																					
		Expense	Depreciation Amount																		
Occurrence 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Net Book Value																					
Beginning Balance		0	305,296	289,228	273,160	257,091	241,023	224,955	208,887	192,819	176,750	160,682	144,614	128,546	112,477	96,409	80,341	64,273	48,205	32,136	16,068
Original Book Value		321,364	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus: Major Maintenance		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less: Depreciation		(16,068)	(16,068)	(16,068)	(16,068)	(16,068)	(16,068)	(16,068)	(16,068)	(16,068)	(16,068)	(16,068)	(16,068)	(16,068)	(16,068)	(16,068)	(16,068)	(16,068)	(16,068)	(16,068)	(16,068)
Net Book Value		305,296	289,228	273,160	257,091	241,023	224,955	208,887	192,819	176,750	160,682	144,614	128,546	112,477	96,409	80,341	64,273	48,205	32,136	16,068	0

Nova Scotia COMFIT Model		Large Wind (Over 50 kW)	
Assumptions		Notes:	
General Inflation Factor (revenue and expenses)		1.92%	From NSPI 2009 IRP Update
Capital Costs (Uses of Funds)			
Development	\$500,000		
Equipment & Installation	\$2,565,000		
Interconnection	\$209,000		
Reserves			
Up-Front Maintenance	\$27,500	(Half of year-one O&M)	
Working Capital	\$40,074	(Half of year-one expenses)	
Debt Service Reserve	\$110,346	(Half of year-one debt service.)	
Financing			
Debt Closing Costs & Fees	\$113,340	(Summed from below)	
Equity Closing Costs & Fees	\$75,600		
Interest During Construction	\$138,700		
Total Project Cost	\$3,779,559		
Total Project Cost (\$/kW)	\$2,520		
Initial Reserve Account Sizing			
Upfront Maintenance (months of Year 1 O&M)	6		
Working Capital (months of Year 1 OPEX)	6		
Debt Service Reserve (months of P&I)	6		
Capital Structure (Sources of Funds)			
Amount (\$)			
Grants (net value)	0		
Debt	1,889,000		
Equity	1,890,559		
Total Sources of Funds	3,779,559		
Amount (%)			
Grants	0.0%		
Debt	50%		
Equity	50%		
Total Sources of Funds	100.0%		
Grants:			
State and Federal Incentives	0		
State/Provincial Tax 1	0		
State/Provincial Tax 2	0		
Federal tax	0		
Net Value of Grants	0		
Debt Terms			
Amount	1,889,000	(Based on target debt/equity ratio)	
Amortization period	15		
Interest Rate	8.00%		
Up-Front Fee (%)	1.00%		
Up-Front Fee (\$)	18,890		
Closing Costs	94,450	(5% of loan value)	
Tax Depreciation Allocation			
% of Total Project Cost			
30% Double Declining	0.0%	95% of hard costs	
50% Double Declining	64.5%		
20-yr SL	0.0%		
40-yr SL	0.0%		
Other	0.0%		
Non-Depreciable	35.53%		
Total	100.0%		
Amount Allocated			
30% Double Declining	0		
50% Double Declining	2,436,750		
20-yr SL	0		
40-yr SL	0		
Other	0		
Non-Depreciable	1,342,809		
Total	3,779,559		
Year One Depreciation			
Year One Percent	25.0%	(Based on the "half year rule")	
Year One Amount	609,188		

Assumptions Worksheet: All		Synapse Exhibit J	
Assumptions:		Notes:	
Operating Inputs			
Net Generator Capacity (MW)	1.50		
Energy Production:			
Net Capacity Factor	31%	Net of plant availability and other loss factors	
Net Output in MWhs	4,073		
Annual Operating Expenses			
Annual Fuel Cost			
Fuel Required per Year (mmBtu)	0		
Initial year Fuel Price (\$/mmBtu)	0		
Annual O&M (expensed)	55,000	Escalates at inflation.	
Site Maintenance	0	Escalates at inflation.	
General & Administrative	1,000	Escalates at inflation.	
Insurance	7,695	Escalates at inflation.	
Land Lease	14,400	2.5% of year one revenues.	
Other	0	Escalates at inflation.	
Property Tax			
Project hard costs less interconnection	2,565,000		
Assessed Value (%)	20.00%		
Assessed Value (\$)	513,000		
Annual Decline in Assessed Value	1.00%		
Assessed Value Minimum %	0.00%		
Property Tax Rate	0.40%	Based on wind property tax law. Escalates at inflation.	
Revenue Assumptions			
Levelized Energy Price (\$/MWh)	142.10		
% of Levelized Rate Escalating @ Infl.	0.0%		
Other Revenues (increases with inflation)	0		
Return Metrics			
20-year Equity IRR			
Pre-Tax	14.33%		
After-Tax	12.98%		
Average Debt Service Coverage Ratio	2.22		
Minimum Debt Service Coverage Ratio	2.17		
Minimum Annual After-Tax Equity Net Benefits	166,657	Includes tax benefit/(liability)	
Tax Rates:			
Federal Income Tax	15.0%		
State/Provincial Income Tax			
Tax Rate 1			
Applicable Income (less than X)	400,000		
Tax Rate 1	4.5%		
Tax Rate 2 (for income greater than X)	16.0%		
Major Maintenance			
Replacement Occurs Every X Years	5		
Cost of Replacement (Year 0 Dollars)	0		
	50% Double		
Tax Depreciation Classification of Spending	Declining		
Book Depreciation Classification of Spending	30-yr SL		
Residual Value			
Residual Value (Net Book Value)	(0)		
Book Depreciation Classifications			
20-yr SL	100.0%		
30-yr SL	0.0%		
37-yr SL	0.0%		
40-yr SL	0.0%		
Non-Depreciable	0.00%		
Total	100.0%		
Amount Allocated			
20-yr SL	3,779,559		
30-yr SL	0		
37-yr SL	0		
40-yr SL	0		
Non-Depreciable	0		
Total	3,779,559		

Nova Scotia COMFIT Model

Large Wind Cash Flow Worksheet: Top

Synapse Exhibit J

Operating Year		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Generation (MWh)			4,073	4,073	4,073	4,073	4,073	4,073	4,073	4,073	4,073	4,073	4,073	4,073	4,073	4,073	4,073	4,073	4,073	4,073	4,073	4,073
Partial Income Statement																						
Revenue																						
Standard Offer Price (\$/MWh)																						
Fixed Price Component	100%	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10
Escalating Price Component	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Standard Offer Price		142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10
Revenues From Energy Production		578,830	578,830	578,830	578,830	578,830	578,830	578,830	578,830	578,830	578,830	578,830	578,830	578,830	578,830	578,830	578,830	578,830	578,830	578,830	578,830	578,830
Other Revenues		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Revenue		3,416	3,416	3,416	3,416	3,416	3,416	3,416	3,416	3,416	3,416	3,416	3,416	3,416	3,416	3,416	3,416	1,297	1,297	1,297	1,297	1,297
Total Revenue		582,246	582,246	582,246	582,246	582,246	582,246	582,246	582,246	582,246	582,246	582,246	582,246	582,246	582,246	582,246	582,246	580,128	580,128	580,128	580,128	580,128
Expenses																						
Fuel Cost		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O&M		(55,000)	(56,056)	(57,132)	(58,229)	(59,347)	(60,487)	(61,648)	(62,832)	(64,038)	(65,268)	(66,521)	(67,798)	(69,100)	(70,426)	(71,779)	(73,157)	(74,561)	(75,993)	(77,452)	(78,939)	
Site Maintenance		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
G&A		(1,000)	(1,019)	(1,039)	(1,059)	(1,079)	(1,100)	(1,121)	(1,142)	(1,164)	(1,187)	(1,209)	(1,233)	(1,256)	(1,280)	(1,305)	(1,330)	(1,356)	(1,382)	(1,408)	(1,435)	
Insurance		(7,695)	(7,843)	(7,993)	(8,147)	(8,303)	(8,463)	(8,625)	(8,791)	(8,960)	(9,132)	(9,307)	(9,486)	(9,668)	(9,853)	(10,042)	(10,235)	(10,432)	(10,632)	(10,836)	(11,044)	
Land Lease		(14,400)	(14,676)	(14,958)	(15,245)	(15,538)	(15,837)	(16,141)	(16,450)	(16,766)	(17,088)	(17,416)	(17,751)	(18,092)	(18,439)	(18,793)	(19,154)	(19,521)	(19,896)	(20,278)	(20,668)	
Other		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Property tax		(2,052)	(2,031)	(2,011)	(1,990)	(1,970)	(1,949)	(1,929)	(1,908)	(1,888)	(1,867)	(1,847)	(1,826)	(1,806)	(1,785)	(1,765)	(1,744)	(1,724)	(1,703)	(1,683)	(1,662)	
Total		(80,147)	(81,626)	(83,134)	(84,671)	(86,238)	(87,835)	(89,463)	(91,124)	(92,816)	(94,541)	(96,300)	(98,093)	(99,921)	(101,784)	(103,684)	(105,620)	(107,594)	(109,606)	(111,657)	(113,748)	
EBITDA		502,099	500,620	499,113	497,576	496,009	494,411	492,783	491,123	489,430	487,705	485,946	484,153	482,325	480,462	478,562	474,508	472,534	470,521	468,470	466,379	
Equity Return																						
Cash																						
EBITDA		502,099	500,620	499,113	497,576	496,009	494,411	492,783	491,123	489,430	487,705	485,946	484,153	482,325	480,462	478,562	474,508	472,534	470,521	468,470	466,379	
Plus: Release of Debt Service Reserve		0	0	0	0	0	0	0	0	0	0	0	0	0	0	110,346	0	0	0	0	0	
Plus: Release of WC & Up-Front Maint Reserves		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	67,574	
Plus: Release of Major Maintenance Reserves		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Plus: Residual Value		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(0)	
Less: Major Maintenance Spending		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Less: Major Maintenance Reserve Funding		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Less: Principal		(69,571)	(75,137)	(81,148)	(87,639)	(94,651)	(102,223)	(110,400)	(119,232)	(128,771)	(139,073)	(150,199)	(162,214)	(175,192)	(189,207)	(204,344)	0	0	0	0	0	
Less: Interest		(151,120)	(145,554)	(139,543)	(133,052)	(126,040)	(118,468)	(110,291)	(101,459)	(91,920)	(81,618)	(70,492)	(58,477)	(45,499)	(31,484)	(16,347)	(0)	(0)	(0)	(0)	(0)	
Total Cash		281,408	279,929	278,422	276,885	275,318	273,720	272,092	270,432	268,739	267,014	265,255	263,462	261,634	259,771	368,217	474,508	472,534	470,521	468,470	533,953	
Equity Investment		(1,890,559)																				
Total Pre-Tax Equity Return		(1,890,559)	281,408	279,929	278,422	276,885	275,318	273,720	272,092	270,432	268,739	267,014	265,255	263,462	261,634	259,771	368,217	474,508	472,534	470,521	468,470	533,953
Pre-Tax Internal Rate of Return	14.33%																					
Taxable Income Benefit/(Liability)																						
EBITDA		502,099	500,620	499,113	497,576	496,009	494,411	492,783	491,123	489,430	487,705	485,946	484,153	482,325	480,462	478,562	474,508	472,534	470,521	468,470	466,379	
Less: Interest		(151,120)	(145,554)	(139,543)	(133,052)	(126,040)	(118,468)	(110,291)	(101,459)	(91,920)	(81,618)	(70,492)	(58,477)	(45,499)	(31,484)	(16,347)	(0)	(0)	(0)	(0)	(0)	
Less: Tax Depreciation		(609,188)	(913,781)	(456,891)	(228,445)	(114,223)	(57,111)	(28,556)	(14,278)	(7,139)	(3,569)	(1,785)	(892)	(446)	(223)	(112)	(56)	(28)	(14)	(7)	(3)	
Taxable Income/(Loss)		(258,208)	(558,715)	(97,321)	136,079	255,746	318,831	353,936	375,386	390,371	402,517	413,669	424,784	436,380	448,755	462,103	474,452	472,506	470,508	468,463	466,376	
Tax Benefit/(Liability)																						
State/Provincial 1		11,619	18,000	4,379	(6,124)	(11,509)	(14,347)	(15,927)	(16,892)	(17,567)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	
State/Provincial 2		0	25,394	0	0	0	0	0	0	0	(403)	(2,187)	(3,965)	(5,821)	(7,801)	(9,937)	(11,912)	(11,601)	(11,281)	(10,954)	(10,620)	
Federal		38,731	83,807	14,598	(20,412)	(38,362)	(47,825)	(53,090)	(56,308)	(58,556)	(60,378)	(62,050)	(63,718)	(65,457)	(67,313)	(69,316)	(71,168)	(70,876)	(70,576)	(70,269)	(69,956)	
Total Tax Benefit/(Liability)		50,351	127,202	18,978	(26,535)	(49,870)	(62,172)	(69,018)	(73,200)	(76,122)	(78,780)	(82,237)	(85,683)	(89,278)	(93,114)	(97,252)	(101,080)	(100,477)	(99,857)	(99,224)	(98,576)	
Equity Investment		(1,890,559)																				
Total After-Tax Equity Return		(1,890,559)	331,759	407,131	297,399	250,349	225,447	211,548	203,074	192,617	188,234	183,018	177,779	172,357	166,657	270,965	373,427	372,057	370,664	369,247	435,376	
After-Tax Internal Rate of Return	12.98%																					

Nova Scotia COMFIT Model

Large Wind Cash Flow Worksheet: Bottom

Synapse Exhibit J

Operating Year		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Debt																						
Loan Balance		1,889,000	1,819,429	1,744,292	1,663,145	1,575,505	1,480,855	1,378,632	1,268,232	1,148,999	1,020,228	881,155	730,957	568,742	393,550	204,344	0	0	0	0	0	0
Interest	8.00%	(1,421,365)	(151,120)	(145,554)	(139,543)	(133,052)	(126,040)	(118,468)	(110,291)	(101,459)	(91,920)	(81,618)	(70,492)	(58,477)	(45,499)	(31,484)	(16,347)	(0)	(0)	(0)	(0)	(0)
Principal		(1,889,000)	(69,571)	(75,137)	(81,148)	(87,639)	(94,651)	(102,223)	(110,400)	(119,232)	(128,771)	(139,073)	(150,199)	(162,214)	(175,192)	(189,207)	(204,344)	0	0	0	0	0
Annual payment			(220,691)	(220,691)	(220,691)	(220,691)	(220,691)	(220,691)	(220,691)	(220,691)	(220,691)	(220,691)	(220,691)	(220,691)	(220,691)	(220,691)	(220,691)	0	0	0	0	0
Debt Service Coverage Ratio																						
EBITDA			502,099	500,620	499,113	497,576	496,009	494,411	492,783	491,123	489,430	487,705	485,946	484,153	482,325	480,462	478,562	0	0	0	0	0
Less: Major Maintenance Reserve Funding			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cash Available for Debt Service			502,099	500,620	499,113	497,576	496,009	494,411	492,783	491,123	489,430	487,705	485,946	484,153	482,325	480,462	478,562	0	0	0	0	0
P&I			220,691	220,691	220,691	220,691	220,691	220,691	220,691	220,691	220,691	220,691	220,691	220,691	220,691	220,691	220,691	0	0	0	0	0
Debt Service Coverage Ratio			2.28	2.27	2.26	2.25	2.25	2.24	2.23	2.23	2.22	2.21	2.20	2.19	2.19	2.18	2.17					
Average		2.22																				
Minimum		2.17																				
Reserve Accounts																						
Reserves Funded As Part of Capital Cost																						
Beginning Balance		0	177,919	177,919	177,919	177,919	177,919	177,919	177,919	177,919	177,919	177,919	177,919	177,919	177,919	177,919	177,919	67,574	67,574	67,574	67,574	67,574
Up-Front Maintenance Reserve		27,500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(27,500)
Working Capital		40,074	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(40,074)
Debt Service Reserve		110,346	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(110,346)	0	0	0	0	0
Total		177,919	177,919	177,919	177,919	177,919	177,919	177,919	177,919	177,919	177,919	177,919	177,919	177,919	177,919	177,919	67,574	67,574	67,574	67,574	67,574	0
Major Maintenance Reserve Funded Through Operations																						
Beginning Balance			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Funding			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Release of Funds			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ending Balance			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Major Maintenance Costs																						
Occurrence 1		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Major Maintenance Funding																						
Occurrence 1		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest on Reserves			3,416	3,416	3,416	3,416	3,416	3,416	3,416	3,416	3,416	3,416	3,416	3,416	3,416	3,416	3,416	1,297	1,297	1,297	1,297	1,297
Property Tax Calculation																						
Original Assessed Value		513,000	513,000	513,000	513,000	513,000	513,000	513,000	513,000	513,000	513,000	513,000	513,000	513,000	513,000	513,000	513,000	513,000	513,000	513,000	513,000	513,000
Annual Decline in Assessed Value		100.0%	99.0%	98.0%	97.0%	96.0%	95.0%	94.0%	93.0%	92.0%	91.0%	90.0%	89.0%	88.0%	87.0%	86.0%	85.0%	84.0%	83.0%	82.0%	81.0%	
Annual Assessed Value		513,000	507,870	502,740	497,610	492,480	487,350	482,220	477,090	471,960	466,830	461,700	456,570	451,440	446,310	441,180	436,050	430,920	425,790	420,660	415,530	
Property Tax Rate		0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	
Property Tax Expense		2,052	2,031	2,011	1,990	1,970	1,949	1,929	1,908	1,888	1,867	1,847	1,826	1,806	1,785	1,765	1,744	1,724	1,703	1,683	1,662	

Operating Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Calendar Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Tax Depreciation																					
Calendar Year Depreciation per Classification (%)																					
30% Double Declining		30.00%	21.00%	14.70%	10.29%	7.20%	5.04%	3.53%	2.47%	1.73%	1.21%	0.85%	0.59%	0.42%	0.29%	0.20%	0.14%	0.10%	0.07%	0.05%	0.03%
50% Double Declining		50.00%	25.00%	12.50%	6.25%	3.13%	1.56%	0.78%	0.39%	0.20%	0.10%	0.05%	0.02%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20-yr SL		2.50%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
40-yr SL		1.25%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Other		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Calendar Year Depreciation per Classification (\$)																					
Year One Capital Cost Allocation	609,188	609,188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30% Double Declining	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
50% Double Declining	1,827,563	0	913,781	456,891	228,445	114,223	57,111	28,556	14,278	7,139	3,569	1,785	892	446	223	112	56	28	14	7	3
20-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Major Maintenance		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Annual Depreciation	2,436,747	609,188	913,781	456,891	228,445	114,223	57,111	28,556	14,278	7,139	3,569	1,785	892	446	223	112	56	28	14	7	3
Major Maintenance																					
Timing of Spending																					
Occurrence 1		0	0	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Occurrence 2		0	0	0	0	0	0	0	0	0	1	2	3	4	5	6	7	8	9	10	11
Occurrence 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	3	4	5	6
Occurrence 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Depreciation Classification																					
Year	50% Double																				
Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Depreciation Schedule	0.00%	50.00%	25.00%	12.50%	6.25%	3.13%	1.56%	0.78%	0.39%	0.20%	0.10%	0.05%	0.02%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Depreciation Expense																					
	Expense	Depreciation																			
Occurrence 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Operating Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20										
Calendar Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030										
Book Depreciation																															
Calendar Year Depreciation per Classification (%)																															
20-yr SL		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%										
30-yr SL		3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%										
37-yr SL		2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%										
40-yr SL		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%										
Calendar Year Depreciation per Classification (\$)																															
20-yr SL	3,779,559	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978										
30-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0										
37-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0										
40-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0										
Major Maintenance		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0										
Annual Depreciation	3,779,559	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978	188,978										
Major Maintenance																															
Timing of Spending																															
Occurrence 1		0	0	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16										
Occurrence 2		0	0	0	0	0	0	0	0	0	1	2	3	4	5	6	7	8	9	10	11										
Occurrence 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	3	4	5	6										
Occurrence 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1										
Depreciation Classification																															
Year	30-yr SL	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20									
Depreciation Schedule		0.00%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%										
Depreciation Expense																															
		<table><tr><th>Expense</th><th>Depreciation Amount</th></tr><tr><td>Occurrence 1</td><td>0</td></tr><tr><td>Occurrence 2</td><td>0</td></tr><tr><td>Occurrence 3</td><td>0</td></tr><tr><td>Occurrence 4</td><td>0</td></tr></table>																				Expense	Depreciation Amount	Occurrence 1	0	Occurrence 2	0	Occurrence 3	0	Occurrence 4	0
Expense	Depreciation Amount																														
Occurrence 1	0																														
Occurrence 2	0																														
Occurrence 3	0																														
Occurrence 4	0																														
Occurrence 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0										
Occurrence 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0										
Occurrence 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0										
Occurrence 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0										
Net Book Value																															
Beginning Balance	0	3,590,581	3,401,603	3,212,625	3,023,647	2,834,669	2,645,691	2,456,713	2,267,735	2,078,757	1,889,780	1,700,802	1,511,824	1,322,846	1,133,868	944,890	755,912	566,934	377,956	188,978											
Original Book Value	3,779,559	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0										
Plus: Major Maintenance	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0										
Less: Depreciation		(188,978)	(188,978)	(188,978)	(188,978)	(188,978)	(188,978)	(188,978)	(188,978)	(188,978)	(188,978)	(188,978)	(188,978)	(188,978)	(188,978)	(188,978)	(188,978)	(188,978)	(188,978)	(188,978)	(188,978)										
Net Book Value		3,590,581	3,401,603	3,212,625	3,023,647	2,834,669	2,645,691	2,456,713	2,267,735	2,078,757	1,889,780	1,700,802	1,511,824	1,322,846	1,133,868	944,890	755,912	566,934	377,956	188,978	(0)										

Biomass CHP Cost Scenarios

Synapse Exhibit K

Condensing turbine with steam-only boiler in year 10

Scenarios in \$2012

Component	Value for Steam-Only Scenario	Gross Value for CHP Scenario	Net Value for CHP Scenario
Project development	\$42,134	\$280,280	\$238,146
Boiler installed cost (\$)	\$1,685,370	\$3,057,600	\$1,372,230
Turbine installed cost (\$)	\$0	\$2,894,528	\$2,894,528
Emission controls	\$252,806	\$305,760	\$52,954
Condenser/Cooling Tower	\$0	\$1,630,720	\$1,630,720
Equipment and Installation (\$)	\$1,938,176	\$7,888,608	\$5,950,432
Interconnection (\$)	\$0	\$199,000	\$199,000
Maintenance reserve (\$)	\$65,279	\$86,632	\$21,353
Working capital reserve (\$)	\$535,312	\$950,152	\$414,840
Debt service reserve (\$)	\$213,498	\$777,905	\$564,407
Debt Closing Costs & Fees	\$109,646	\$399,506	\$289,860
Equity Closing Costs & Fees	\$48,718	\$177,585	\$128,868
Interest During Construction	\$91,371	\$332,922	\$241,550
Routine Maintenance (\$/yr)	\$130,557	\$173,264	\$42,707
Labour (\$)	\$305,760	\$356,720	\$50,960
General & Admin.	\$0	\$0	\$0
Insurance	\$9,691	\$39,443	\$29,752
Property taxes	\$0	\$3,567	
Year-10 Turbine overhaul (\$)	\$0	\$152,880	\$152,880
Year-10 Boiler overhaul (\$)	\$0	\$203,840	\$203,840
Annual Fuel Use (mmBtu/yr)	\$147,315	\$313,045	\$165,730
Annual Fuel Cost (\$/yr)	\$624,616	\$1,327,310	\$702,693
Plant capacity factor (%) - extract	60%	60%	60%
Plant capacity factor (%) - full condensing		25%	25%
NPV of new boiler(\$2M) in yr 10	\$1,685,370		
Steam Load (mmBtu/hr)	22	22	22
Boiler size (lb/hr)	20,000	30,000	
Boiler rating (psi)	75-100	600	
Turbine type	N/A	Condensing	
Turbine size (MW)	N/A	2.05	
Total Project Costs (\$)	\$3,044,134	\$11,092,590	\$8,048,456
Total Project Costs (\$/kW)		\$5,411	\$3,926

Actual Loan Value:	\$1,826,480	\$6,655,554	\$4,829,074
Actual Equity Amount:	\$1,217,653	\$4,437,036	

Calculation of fuel costs:	extraction
turbine size (kW):	1550
Boiler efficiency (%)	80%
Adjusted turbine size (kW):	
Adjusted KWhs:	
Fuel Use (Btu):	
Fuel Use (mmBtu):	216810

Calculation of heat input:
5,256 hrs
115,632 process heat (mmBtu)
144,540 heat input (mmBtu)

Efficiency:	51%
Steam energy	117852.1344
Electric Energy	43115
Fuel Use	313045

Nova Scotia COMFIT Model

Assumptions		Notes:
General Inflation Factor (revenue and expenses)	1.92%	From NSPI 2009 IRP Update
Capital Costs (Uses of Funds)		
Development	238,146	Net of steam-only scenario
Equipment & Installation	5,950,432	Net of steam-only scenario
Interconnection	199,000	Net of steam-only scenario
Reserves		
Up-Front Maintenance	21,353	Net of steam-only scenario
Working Capital	414,840	Net of steam-only scenario
Debt Service Reserve	564,407	Net of steam-only scenario
Financing		
Debt Closing Costs & Fees	289,860	Net of steam-only scenario
Equity Closing Costs & Fees	128,868	Net of steam-only scenario
Interest During Construction	241,550	Net of steam-only scenario
Total Project Cost	8,048,456	Net of steam-only scenario
Total Project Cost (\$/kW)	3,926	Net of steam-only scenario
Initial Reserve Account Sizing		
Upfront Maintenance (months of Year 1 O&M)	6	
Working Capital (months of Year 1 OPEX)	6	
Debt Service Reserve (months of P&I)	6	
Capital Structure (Sources of Funds)		
Amount (\$)		
Grants (net value)	0	
Debt	4,829,074	
Equity	3,219,383	
Total Sources of Funds	8,048,456	
Amount (%)		
Grants	0.0%	
Debt	60.0%	
Equity	40.0%	
Total Sources of Funds	100.0%	
Grants:		
State and Federal Incentives	0	
State/Provincial Tax 1	0	
State/Provincial Tax 2	0	
Federal tax	0	
Net Value of Grants	0	
Debt Terms		
Amount	4,829,074	(Based on target debt/equity ratio)
Loan Life	15	
Interest Rate	9.50%	
Up-Front Fee (%)	1.00%	
Up-Front Fee (\$)	48,291	
Closing Costs	241,454	(5% of loan value)
Tax Depreciation Allocation		
% of Total Project Cost		
30% Double Declining	0.0%	
50% Double Declining	70.2%	95% of equipment and installation
20-yr SL	0.0%	
40-yr SL	0.0%	
Other	0.0%	
Non-Depreciable	29.76%	
Total	100.0%	
Amount Allocated		
30% Double Declining	0	
50% Double Declining	5,652,911	
20-yr SL	0	
40-yr SL	0	
Other	0	
Non-Depreciable	2,395,545	
Total	8,048,456	
Year One Depreciation		
Year One Percent	25.0%	(Based on the "half year rule")
Year One Amount	1,413,228	

Biomass CHP (condensing turbine; new boiler in steam-only scenario in year 10)

Assumptions:		Notes:
Operating Inputs		
Net Generator Capacity (MW)	2.05	1.55 MW at full extraction, 2.05 MW at full condensing
Energy Production:		
Net Capacity Factor		
Net Output in MWhs	12,636	60% of time at full extraction, another 25% at full condensing
Annual Operating Expenses		
Annual Fuel Cost		
Fuel Required per Year (mmBtu)	165,730	Net of steam-only scenario
Initial year Fuel Price (\$/mmBtu)	\$4.24	
Annual O&M (expensed)	93,667	Net of steam-only scenario, escalates at inflation.
Site Maintenance	0	Net of steam-only scenario, escalates at inflation.
General & Administrative	0	Net of steam-only scenario, escalates at inflation.
Insurance	29,752	Net of steam-only scenario, escalates at inflation.
Land Lease	0	Net of steam-only scenario, escalates at inflation.
Other	0	Net of steam-only scenario, escalates at inflation.
Property Tax		
Project Hard Costs	5,950,432	
Assessed Value (%)	1.68%	Machinery and equipment is not assessed.
Assessed Value (\$)	100,000	
Annual Decline in Assessed Value	1.00%	
Assessed Value Minimum %	0.00%	
Property Tax Rate	3.50%	
Revenue Assumptions		
Levelized Energy Price (\$/MWh)	156.10	
% of Levelized Rate Escalating @ Infl.	0.0%	
Other Revenues (increases with inflation)	0	
Return Metrics		
20-year Equity IRR		
Pre-Tax	13.79%	
After-Tax	12.99%	
Average Debt Service Coverage Ratio	1.65	
Minimum Debt Service Coverage Ratio	1.48	
Minimum Annual After-Tax Equity Net Benefits	111,682	Includes tax benefit/(liability)
Tax Rates:		
Federal Income Tax	15.0%	
State/Provincial Income Tax		
Tax Rate 1		
Applicable Income (less than X)	400,000	
Tax Rate 1	4.5%	
Tax Rate 2 (for income greater than X)	16.0%	
Major Maintenance		
Replacement Occurs Every X Years	11	
Cost of Replacement (Year 0 Dollars)	356,720	
	50% Double	
Tax Depreciation Classification of Spending	Declining	
Book Depreciation Classification of Spending	30-yr SL	
Residual Value		
Residual Value (Net Book Value)	421	
Book Depreciation Classifications		
20-yr SL	100.0%	
30-yr SL	0.0%	
37-yr SL	0.0%	
40-yr SL	0.0%	
Non-Depreciable	0.00%	
Total	100.0%	
Amount Allocated		
20-yr SL	8,048,456	
30-yr SL	0	
37-yr SL	0	
40-yr SL	0	
Non-Depreciable	0	
Total	8,048,456	

Synapse Exhibit K

Nova Scotia COMFIT Model

Biomass Cash Flow Worksheet: Bottom

Synapse Exhibit K

Operating Year		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Debt																						
Loan Balance		4,829,074	4,670,952	4,497,809	4,308,217	4,100,614	3,873,288	3,624,367	3,351,798	3,053,335	2,726,518	2,368,654	1,976,792	1,547,704	1,077,852	563,364	(0)	(0)	(0)	(0)	(0)	(0)
Interest	9.50%	(4,424,182)	(458,762)	(443,740)	(427,292)	(409,281)	(389,558)	(367,962)	(344,315)	(318,421)	(290,067)	(259,019)	(225,022)	(187,795)	(147,032)	(102,396)	(53,520)	0	0	0	0	0
Principal		(4,829,074)	(158,122)	(173,143)	(189,592)	(207,603)	(227,325)	(248,921)	(272,569)	(298,463)	(326,817)	(357,864)	(391,862)	(429,088)	(469,852)	(514,488)	(563,364)	(0)	(0)	(0)	(0)	(0)
Annual payment			(616,884)	(616,884)	(616,884)	(616,884)	(616,884)	(616,884)	(616,884)	(616,884)	(616,884)	(616,884)	(616,884)	(616,884)	(616,884)	(616,884)	(616,884)	0	0	0	0	0
Debt Service Coverage Ratio																						
EBITDA		1,162,126	1,147,053	1,131,675	1,115,987	1,099,982	1,083,655	1,066,999	1,050,009	1,032,677	1,014,997	996,963	970,284	950,766	930,874	910,599		0	0	0	0	0
Less: Major Maintenance Reserve Funding		(39,222)	(39,222)	(39,222)	(39,222)	(39,222)	(39,222)	(39,222)	(39,222)	(39,222)	(39,222)	(39,222)	0	0	0	0		0	0	0	0	0
Cash Available for Debt Service		1,122,904	1,107,831	1,092,453	1,076,765	1,060,760	1,044,433	1,027,777	1,010,787	993,455	975,775	957,741	970,284	950,766	930,874	910,599		0	0	0	0	0
P&I		616,884	616,884	616,884	616,884	616,884	616,884	616,884	616,884	616,884	616,884	616,884	616,884	616,884	616,884	616,884		0	0	0	0	0
Debt Service Coverage Ratio		1.82	1.80	1.77	1.75	1.72	1.69	1.67	1.64	1.61	1.58	1.55	1.57	1.54	1.51	1.48						
Average		1.65																				
Minimum		1.48																				
Reserve Accounts																						
Reserves Funded As Part of Capital Cost																						
Beginning Balance	0	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	436,193	436,193	436,193	436,193	436,193	436,193
Up-Front Maintenance Reserve	21,353	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(21,353)
Working Capital	414,840	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(414,840)
Debt Service Reserve	564,407	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(564,407)	0	0	0	0	0
Total	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	1,000,600	436,193	436,193	436,193	436,193	436,193	(0)
Major Maintenance Reserve Funded Through Operations																						
Beginning Balance	0	39,222	78,444	117,666	156,888	196,110	235,332	274,553	313,775	352,997	392,219		0	0	0	0	0	0	0	0	0	0
Funding	39,222	39,222	39,222	39,222	39,222	39,222	39,222	39,222	39,222	39,222	39,222	39,222	0	0	0	0	0	0	0	0	0	0
Release of Funds	0	0	0	0	0	0	0	0	0	0	0	(431,441)	0	0	0	0	0	0	0	0	0	0
Ending Balance	39,222	78,444	117,666	156,888	196,110	235,332	274,553	313,775	352,997	392,219	0	0	0	0	0	0	0	0	0	0	0	0
Major Maintenance Costs																						
Occurrence 1	431,441	0	0	0	0	0	0	0	0	0	0	431,441	0	0	0	0	0	0	0	0	0	0
Occurrence 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Major Maintenance Funding																						
Occurrence 1	431,441	39,222	39,222	39,222	39,222	39,222	39,222	39,222	39,222	39,222	39,222	39,222	0	0	0	0	0	0	0	0	0	0
Occurrence 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest on Reserves		19,212	19,965	20,718	21,471	22,224	22,977	23,730	24,483	25,236	25,989	26,742	19,212	19,212	19,212	19,212	8,375	8,375	8,375	8,375	8,375	8,375
Property Tax Calculation																						
Original Assessed Value		100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Annual Decline in Assessed Value		100.0%	99.0%	98.0%	97.0%	96.0%	95.0%	94.0%	93.0%	92.0%	91.0%	90.0%	89.0%	88.0%	87.0%	86.0%	85.0%	84.0%	83.0%	82.0%	81.0%	81.0%
Annual Assessed Value		100,000	99,000	98,000	97,000	96,000	95,000	94,000	93,000	92,000	91,000	90,000	89,000	88,000	87,000	86,000	85,000	84,000	83,000	82,000	81,000	81,000
Property Tax Rate		3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Property Tax Expense		3,500	3,465	3,430	3,395	3,360	3,325	3,290	3,255	3,220	3,185	3,150	3,115	3,080	3,045	3,010	2,975	2,940	2,905	2,870	2,835	2,835

Operating Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Calendar Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Tax Depreciation																					
Calendar Year Depreciation per Classification (%)																					
30% Double Declining		30.00%	21.00%	14.70%	10.29%	7.20%	5.04%	3.53%	2.47%	1.73%	1.21%	0.85%	0.59%	0.42%	0.29%	0.20%	0.14%	0.10%	0.07%	0.05%	0.03%
50% Double Declining		50.00%	25.00%	12.50%	6.25%	3.13%	1.56%	0.78%	0.39%	0.20%	0.10%	0.05%	0.02%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20-yr SL		2.50%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
40-yr SL		1.25%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Other		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Calendar Year Depreciation per Classification (\$)																					
Year One Capital Cost Allocation	1,413,228	1,413,228	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30% Double Declining	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
50% Double Declining	4,239,683	0	2,119,842	1,059,921	529,960	264,980	132,490	66,245	33,123	16,561	8,281	4,140	2,070	1,035	518	259	129	65	32	16	8
20-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Major Maintenance		0	0	0	0	0	0	0	0	0	0	215,721	107,860	53,930	26,965	13,483	6,741	3,371	1,685	843	421
Annual Depreciation	6,083,923	1,413,228	2,119,842	1,059,921	529,960	264,980	132,490	66,245	33,123	16,561	8,281	219,861	109,930	54,965	27,483	13,741	6,871	3,435	1,718	859	429
Major Maintenance																					
Timing of Spending																					
Occurrence 1		0	0	0	0	0	0	0	0	0	0	1	2	3	4	5	6	7	8	9	10
Occurrence 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation Classification																					
Year	50% Double																				
Depreciation Schedule	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
	0.00%	50.00%	25.00%	12.50%	6.25%	3.13%	1.56%	0.78%	0.39%	0.20%	0.10%	0.05%	0.02%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Depreciation Expense																					
	Expense	Depreciation																			
Occurrence 1	431,441	431,020	0	0	0	0	0	0	0	0	0	215,721	107,860	53,930	26,965	13,483	6,741	3,371	1,685	843	421
Occurrence 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Operating Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20										
Calendar Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030										
Book Depreciation																															
Calendar Year Depreciation per Classification (%)																															
20-yr SL		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%										
30-yr SL		3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%										
37-yr SL		2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%										
40-yr SL		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%										
Calendar Year Depreciation per Classification (\$)																															
20-yr SL	8,048,456	402,423	402,423	402,423	402,423	402,423	402,423	402,423	402,423	402,423	402,423	402,423	402,423	402,423	402,423	402,423	402,423	402,423	402,423	402,423	402,423										
30-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0										
37-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0										
40-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0										
Major Maintenance		0	0	0	0	0	0	0	0	0	0	215,721	107,860	53,930	26,965	13,483	6,741	3,371	1,685	843	421										
Annual Depreciation	8,479,476	402,423	402,423	402,423	402,423	402,423	402,423	402,423	402,423	402,423	402,423	618,143	510,283	456,353	429,388	415,905	409,164	405,793	404,108	403,265	402,844										
Major Maintenance																															
Timing of Spending																															
Occurrence 1		0	0	0	0	0	0	0	0	0	0	1	2	3	4	5	6	7	8	9	10										
Occurrence 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0										
Occurrence 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0										
Occurrence 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0										
Depreciation Classification																															
Year	30-yr SL																														
Depreciation Schedule	0.00%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%										
Depreciation Expense																															
	<table><tr><th>Expense</th><th>Depreciation Amount</th></tr><tr><td>Occurrence 1</td><td>431,441</td></tr><tr><td>Occurrence 2</td><td>0</td></tr><tr><td>Occurrence 3</td><td>0</td></tr><tr><td>Occurrence 4</td><td>0</td></tr></table>	Expense	Depreciation Amount	Occurrence 1	431,441	Occurrence 2	0	Occurrence 3	0	Occurrence 4	0																				
Expense	Depreciation Amount																														
Occurrence 1	431,441																														
Occurrence 2	0																														
Occurrence 3	0																														
Occurrence 4	0																														
Occurrence 1	431,441	431,020	0	0	0	0	0	0	0	0	0	215,721	107,860	53,930	26,965	13,483	6,741	3,371	1,685	843	421										
Occurrence 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0										
Occurrence 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0										
Occurrence 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0										
Net Book Value																															
Beginning Balance	0	7,646,034	7,243,611	6,841,188	6,438,765	6,036,342	5,633,919	5,231,497	4,829,074	4,426,651	4,024,228	3,837,526	3,327,243	2,870,890	2,441,502	2,025,597	1,616,433	1,210,639	806,531	403,265											
Original Book Value	8,048,456	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0										
Plus: Major Maintenance	0	0	0	0	0	0	0	0	0	0	0	431,441	0	0	0	0	0	0	0	0	0										
Less: Depreciation		(402,423)	(402,423)	(402,423)	(402,423)	(402,423)	(402,423)	(402,423)	(402,423)	(402,423)	(402,423)	(618,143)	(510,283)	(456,353)	(429,388)	(415,905)	(409,164)	(405,793)	(404,108)	(403,265)	(402,844)										
Net Book Value	7,646,034	7,243,611	6,841,188	6,438,765	6,036,342	5,633,919	5,231,497	4,829,074	4,426,651	4,024,228	3,837,526	3,327,243	2,870,890	2,441,502	2,025,597	1,616,433	1,210,639	806,531	403,265	421											

Nova Scotia COMFIT Model

Assumptions	Run-of-River Hydro	
General Inflation Factor (revenue and expenses)	1.92%	Notes: From NSPI 2009 IRP Update
Capital Costs (Uses of Funds)		
Development	0	
Equipment & Installation	3,900,000	
Interconnection	285,000	
Reserves		
Up-Front Maintenance	25,000	(Half of year-one O&M)
Working Capital	80,625	(Half of year-one expenses)
Debt Service Reserve	155,967	(Half of year-one debt service.)
Financing		
Debt Closing Costs & Fees	0	included in B6
Equity Closing Costs & Fees	0	included in B6
Interest During Construction	0	included in B6
Total Project Cost	4,446,592	
Total Project Cost (\$/kW)	4,447	
Initial Reserve Account Sizing		
Upfront Maintenance (months of Year 1 O&M)	6	
Working Capital (months of Year 1 OPEX)	6	
Debt Service Reserve (months of P&I)	6	
Capital Structure (Sources of Funds)		
Amount (\$)		
Grants (net value)	0	
Debt	2,670,000	
Equity	1,776,592	
Total Sources of Funds	4,446,592	
Amount (%)		
Grants	0.0%	
Debt	60.0%	
Equity	40.0%	
Total Sources of Funds	100.0%	
Grants:		
State and Federal Incentives	0	
State/Provincial Tax 1	0	
State/Provincial Tax 2	0	
Federal tax	0	
Net Value of Grants	0	
Debt Terms		
Amount	2,670,000	(Based on target debt/equity ratio)
Amortization period	15	
Interest Rate	8.00%	
Up-Front Fee (%)	0.00%	included in B6
Up-Front Fee (\$)	0	included in B6
Closing Costs	0	included in B6
Tax Depreciation Allocation		
% of Total Project Cost		
30% Double Declining	0.0%	
50% Double Declining	83.3%	95% of installed cost
20-yr SL	0.0%	
40-yr SL	0.0%	
Other	0.0%	
Non-Depreciable	16.68%	Project development, interconnection, reserves, closing costs
Total	100.0%	
Amount Allocated		
30% Double Declining	0	
50% Double Declining	3,705,000	
20-yr SL	0	
40-yr SL	0	
Other	0	
Non-Depreciable	741,592	
Total	4,446,592	
Year One Depreciation		
Year One Percent	25.0%	(Based on the "half year rule")
Year One Amount	926,250	

Assumptions Worksheet: All

Assumptions:	Notes:	
Operating Inputs		
Net Generator Capacity (MW)	1.00	
Energy Production:		
Net Capacity Factor	55%	Net of plant availability and other loss factors
Net Output in MWhs	4,818	
Annual Operating Expenses		
Annual Fuel Cost		
Fuel Required per Year (mmBtu)	0	
Initial year Fuel Price (\$/mmBtu)	0	
Routine O&M (expensed)	50,000	Includes periodic major maintenance. Escalates at inflation.
Site Maintenance	0	Escalates at inflation.
General & Administrative	1,000	Escalates at inflation.
Insurance	39,000	Escalates at inflation.
Land Lease	2,500	Access lease only.
Other	500	Royalty payment for water use.
Property Tax		
Project hard costs less interconnection	3,900,000	
Assessed Value (%)	50.00%	
Assessed Value (\$)	1,950,000	
Annual Decline in Assessed Value	1.00%	
Assessed Value Minimum %	0.00%	
Property Tax Rate	3.50%	
Revenue Assumptions		
Levelized Energy Price (\$/MWh)	138.10	
% of Levelized Rate Escalating @ Infl.	0.0%	
Other Revenues (increases with inflation)	0	
Return Metrics		
20-year Equity IRR		
Pre-Tax	12.02%	
After-Tax	13.01%	
Average Debt Service Coverage Ratio	1.60	
Minimum Debt Service Coverage Ratio	1.57	
Minimum Annual After-Tax Equity Net Benefits	87,395	Includes tax benefit/(liability)
Tax Rates:		
Federal Income Tax	15.0%	
Provincial Income Tax		
Tax Rate 1		
Applicable to Income less than	\$400,000	
Tax Rate 1	4.5%	
Tax Rate 2 (for income greater than F40)	16.0%	
Major Maintenance		
Replacement Occurs Every X Years	5	This cost is included in routine O&M in cell F12.
Cost of Replacement (Year 0 Dollars)	0	
	50% Double Declining	
Tax Depreciation Classification of Spending		
Book Depreciation Classification of Spending	30-yr SL	
Residual Value		
Residual Value (Net Book Value)	1,170,000	
Book Depreciation Classifications		
20-yr SL	56.1%	
30-yr SL	0.0%	
37-yr SL	0.0%	
50-yr SL	43.9%	
Non-Depreciable	0.00%	
Total	100.0%	
Amount Allocated		
20-yr SL	2,496,592	
30-yr SL	0	
37-yr SL	0	
50-yr SL	1,950,000	
Non-Depreciable	0	
Total	4,446,592	

Synapse Exhibit L

Nova Scotia COMFIT Model

Hydro Cash Flow Worksheet: Top

Synapse Exhibit L

Operating Year		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Generation (MWh)			4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818
Partial Income Statement																						
Revenue																						
Standard Offer Price (\$/MWh)																						
Fixed Price Component	100%	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10
Escalating Price Component	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Standard Offer Price		138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10	138.10
Revenues From Energy Production		665,366	665,366	665,366	665,366	665,366	665,366	665,366	665,366	665,366	665,366	665,366	665,366	665,366	665,366	665,366	665,366	665,366	665,366	665,366	665,366	665,366
Other Revenues		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Revenue		5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	2,028	2,028	2,028	2,028	2,028
Total Revenue		670,388	670,388	670,388	670,388	670,388	670,388	670,388	670,388	670,388	670,388	670,388	670,388	670,388	670,388	670,388	670,388	667,394	667,394	667,394	667,394	667,394
Expenses																						
Fuel Cost		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O&M		(50,000)	(50,960)	(51,938)	(52,936)	(53,952)	(54,988)	(56,044)	(57,120)	(58,216)	(59,334)	(60,473)	(61,634)	(62,818)	(64,024)	(65,253)	(66,506)	(67,783)	(69,084)	(70,411)	(71,763)	(71,763)
Site Maintenance		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
G&A		(1,000)	(1,019)	(1,039)	(1,059)	(1,079)	(1,100)	(1,121)	(1,142)	(1,164)	(1,187)	(1,209)	(1,233)	(1,256)	(1,280)	(1,305)	(1,330)	(1,356)	(1,382)	(1,408)	(1,435)	(1,435)
Insurance		(39,000)	(39,749)	(40,512)	(41,290)	(42,083)	(42,891)	(43,714)	(44,553)	(45,409)	(46,281)	(47,169)	(48,075)	(48,998)	(49,939)	(50,897)	(51,875)	(52,871)	(53,886)	(54,920)	(55,975)	(55,975)
Land Lease		(2,500)	(2,548)	(2,597)	(2,647)	(2,698)	(2,749)	(2,802)	(2,856)	(2,911)	(2,967)	(3,024)	(3,082)	(3,141)	(3,201)	(3,263)	(3,325)	(3,389)	(3,454)	(3,521)	(3,588)	(3,588)
Other		(500)	(510)	(519)	(529)	(540)	(550)	(560)	(571)	(582)	(593)	(605)	(616)	(628)	(640)	(653)	(665)	(678)	(691)	(704)	(718)	(718)
Property tax		(68,250)	(67,568)	(66,885)	(66,203)	(65,520)	(64,838)	(64,155)	(63,473)	(62,790)	(62,108)	(61,425)	(60,743)	(60,060)	(59,378)	(58,695)	(58,013)	(57,330)	(56,648)	(55,965)	(55,283)	(55,283)
Total		(161,250)	(162,353)	(163,490)	(164,663)	(165,871)	(167,115)	(168,396)	(169,715)	(171,072)	(172,469)	(173,905)	(175,383)	(176,901)	(178,462)	(180,066)	(181,714)	(183,406)	(185,145)	(186,929)	(188,761)	(188,761)
EBITDA		509,138	508,035	506,898	505,726	504,518	503,273	501,992	500,673	499,316	497,919	496,483	495,006	493,487	491,926	490,322	485,680	483,987	482,249	480,465	478,633	478,633
Equity Return																						
Cash																						
EBITDA		509,138	508,035	506,898	505,726	504,518	503,273	501,992	500,673	499,316	497,919	496,483	495,006	493,487	491,926	490,322	485,680	483,987	482,249	480,465	478,633	478,633
Plus: Release of Debt Service Reserve		0	0	0	0	0	0	0	0	0	0	0	0	0	0	155,967	0	0	0	0	0	0
Plus: Release of WC & Up-Front Maint Reserves		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	105,625	105,625
Plus: Release of Major Maintenance Reserves		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus: Residual Value		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,170,000
Less: Major Maintenance Spending		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less: Major Maintenance Reserve Funding		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less: Principal		(98,335)	(106,202)	(114,698)	(123,874)	(133,784)	(144,486)	(156,045)	(168,529)	(182,011)	(196,572)	(212,298)	(229,281)	(247,624)	(267,434)	(288,829)	0	0	0	0	0	0
Less: Interest		(213,600)	(205,733)	(197,237)	(188,061)	(178,151)	(167,449)	(155,890)	(143,406)	(129,924)	(115,363)	(99,637)	(82,653)	(64,311)	(44,501)	(23,106)	(0)	(0)	(0)	(0)	(0)	(0)
Total Cash		197,203	196,100	194,963	193,791	192,583	191,339	190,057	188,738	187,381	185,984	184,548	183,071	181,552	179,991	334,355	485,680	483,987	482,249	480,465	1,754,258	1,754,258
Equity Investment		(1,776,592)																				
Total Pre-Tax Equity Return		(1,776,592)	197,203	196,100	194,963	193,791	192,583	191,339	190,057	188,738	187,381	185,984	184,548	183,071	181,552	179,991	334,355	485,680	483,987	482,249	480,465	1,754,258
Pre-Tax Internal Rate of Return	12.02%																					
Taxable Income Benefit/(Liability)																						
EBITDA		509,138	508,035	506,898	505,726	504,518	503,273	501,992	500,673	499,316	497,919	496,483	495,006	493,487	491,926	490,322	485,680	483,987	482,249	480,465	478,633	478,633
Less: Interest		(213,600)	(205,733)	(197,237)	(188,061)	(178,151)	(167,449)	(155,890)	(143,406)	(129,924)	(115,363)	(99,637)	(82,653)	(64,311)	(44,501)	(23,106)	(0)	(0)	(0)	(0)	(0)	(0)
Less: Tax Depreciation		(926,250)	(1,389,375)	(694,688)	(347,344)	(173,672)	(86,836)	(43,418)	(21,709)	(10,854)	(5,427)	(2,714)	(1,357)	(678)	(339)	(170)	(85)	(42)	(21)	(11)	(5)	(5)
Taxable Income/(Loss)		(630,712)	(1,087,073)	(385,027)	(29,679)	152,694	248,989	302,684	335,558	358,538	377,129	394,132	410,996	428,498	447,086	467,047	485,595	483,945	482,228	480,454	478,627	478,627
Tax Benefit/(Liability)																						
State/Provincial 1		18,000	18,000	17,326	1,336	(6,871)	(11,204)	(13,621)	(15,100)	(16,134)	(16,971)	(17,736)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)
State/Provincial 2		36,914	109,932	0	0	0	0	0	0	0	0	0	(1,759)	(4,560)	(7,534)	(10,727)	(13,695)	(13,431)	(13,156)	(12,873)	(12,580)	(12,580)
Federal		94,607	163,061	57,754	4,452	(22,904)	(37,348)	(45,403)	(50,334)	(53,781)	(56,569)	(59,120)	(61,649)	(64,275)	(67,063)	(70,057)	(72,839)	(72,592)	(72,334)	(72,068)	(71,794)	(71,794)
Total Tax Benefit/(Liability)		149,521	290,993	75,080	5,787	(29,775)	(48,553)	(59,023)	(65,434)	(69,915)	(73,540)	(76,856)	(81,409)	(86,834)	(92,597)	(98,784)	(104,535)	(104,023)	(103,491)	(102,941)	(102,374)	(102,374)
Equity Investment		(1,776,592)																				
Total After-Tax Equity Return		(1,776,592)	346,724	487,093	270,043	199,578	162,807	142,786	131,034	123,305	117,466	112,444	107,692	101,662	94,718	87,395	235,571	381,146	379,964	378,759	377,524	1,651,883
After-Tax Internal Rate of Return	13.01%																					

Nova Scotia COMFIT Model

Hydro Cash Flow Worksheet: Bottom

Synapse Exhibit L

Operating Year		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Debt																						
Loan Balance		2,670,000	2,571,665	2,465,463	2,350,766	2,226,892	2,093,108	1,948,622	1,792,577	1,624,048	1,442,037	1,245,466	1,033,168	803,886	556,262	288,829	0	0	0	0	0	0
Interest	8.00%	(2,009,023)	(213,600)	(205,733)	(197,237)	(188,061)	(178,151)	(167,449)	(155,890)	(143,406)	(129,924)	(115,363)	(99,637)	(82,653)	(64,311)	(44,501)	(23,106)	(0)	(0)	(0)	(0)	(0)
Principal		(2,670,000)	(98,335)	(106,202)	(114,698)	(123,874)	(133,784)	(144,486)	(156,045)	(168,529)	(182,011)	(196,572)	(212,298)	(229,281)	(247,624)	(267,434)	(288,829)	0	0	0	0	0
Annual payment			(311,935)	(311,935)	(311,935)	(311,935)	(311,935)	(311,935)	(311,935)	(311,935)	(311,935)	(311,935)	(311,935)	(311,935)	(311,935)	(311,935)	(311,935)	0	0	0	0	0
Debt Service Coverage Ratio																						
EBITDA			509,138	508,035	506,898	505,726	504,518	503,273	501,992	500,673	499,316	497,919	496,483	495,006	493,487	491,926	490,322	0	0	0	0	0
Less: Major Maintenance Reserve Funding			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cash Available for Debt Service			509,138	508,035	506,898	505,726	504,518	503,273	501,992	500,673	499,316	497,919	496,483	495,006	493,487	491,926	490,322	0	0	0	0	0
P&I			311,935	311,935	311,935	311,935	311,935	311,935	311,935	311,935	311,935	311,935	311,935	311,935	311,935	311,935	311,935	0	0	0	0	0
Debt Service Coverage Ratio			1.63	1.63	1.63	1.62	1.62	1.61	1.61	1.61	1.60	1.60	1.59	1.59	1.58	1.58	1.57					
Average		1.60																				
Minimum		1.57																				
Reserve Accounts																						
Reserves Funded As Part of Capital Cost																						
Beginning Balance		0	261,592	261,592	261,592	261,592	261,592	261,592	261,592	261,592	261,592	261,592	261,592	261,592	261,592	261,592	261,592	105,625	105,625	105,625	105,625	105,625
Up-Front Maintenance Reserve		25,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(25,000)
Working Capital		80,625	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(80,625)
Debt Service Reserve		155,967	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(155,967)	0	0	0	0	0
Total		261,592	261,592	261,592	261,592	261,592	261,592	261,592	261,592	261,592	261,592	261,592	261,592	261,592	261,592	261,592	105,625	105,625	105,625	105,625	105,625	0
Major Maintenance Reserve Funded Through Operations																						
Beginning Balance			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Funding			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Release of Funds			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ending Balance			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Major Maintenance Costs																						
Occurrence 1		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Major Maintenance Funding																						
Occurrence 1		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest on Reserves			5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	2,028	2,028	2,028	2,028	2,028
Property Tax Calculation																						
Original Assessed Value		1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000
Annual Decline in Assessed Value		100.0%	99.0%	98.0%	97.0%	96.0%	95.0%	94.0%	93.0%	92.0%	91.0%	90.0%	89.0%	88.0%	87.0%	86.0%	85.0%	84.0%	83.0%	82.0%	81.0%	80.0%
Annual Assessed Value		1,950,000	1,930,500	1,911,000	1,891,500	1,872,000	1,852,500	1,833,000	1,813,500	1,794,000	1,774,500	1,755,000	1,735,500	1,716,000	1,696,500	1,677,000	1,657,500	1,638,000	1,618,500	1,599,000	1,579,500	1,559,000
Property Tax Rate		3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Property Tax Expense		68,250	67,568	66,885	66,203	65,520	64,838	64,155	63,473	62,790	62,108	61,425	60,743	60,060	59,378	58,695	58,013	57,330	56,648	55,965	55,283	54,600

Operating Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Calendar Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Tax Depreciation																					
Calendar Year Depreciation per Classification (%)																					
30% Double Declining		30.00%	21.00%	14.70%	10.29%	7.20%	5.04%	3.53%	2.47%	1.73%	1.21%	0.85%	0.59%	0.42%	0.29%	0.20%	0.14%	0.10%	0.07%	0.05%	0.03%
50% Double Declining		50.00%	25.00%	12.50%	6.25%	3.13%	1.56%	0.78%	0.39%	0.20%	0.10%	0.05%	0.02%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20-yr SL		2.50%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
40-yr SL		1.25%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Other		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Calendar Year Depreciation per Classification (\$)																					
Year One Capital Cost Allocation	926,250	926,250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30% Double Declining	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
50% Double Declining	2,778,750	0	1,389,375	694,688	347,344	173,672	86,836	43,418	21,709	10,854	5,427	2,714	1,357	678	339	170	85	42	21	11	5
20-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Major Maintenance		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Annual Depreciation	3,704,995	926,250	1,389,375	694,688	347,344	173,672	86,836	43,418	21,709	10,854	5,427	2,714	1,357	678	339	170	85	42	21	11	5
Major Maintenance																					
Timing of Spending																					
Occurrence 1		0	0	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Occurrence 2		0	0	0	0	0	0	0	0	0	1	2	3	4	5	6	7	8	9	10	11
Occurrence 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	3	4	5	6
Occurrence 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Depreciation Classification																					
Year	50% Double Declining																				
Depreciation Schedule	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
	0.00%	50.00%	25.00%	12.50%	6.25%	3.13%	1.56%	0.78%	0.39%	0.20%	0.10%	0.05%	0.02%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Depreciation Expense																					
		Expense	Depreciation Amount																		
Occurrence 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Operating Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
Calendar Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	
Book Depreciation																						
Calendar Year Depreciation per Classification (%)																						
20-yr SL		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	
30-yr SL		3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	
37-yr SL		2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	
50-yr SL		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
Calendar Year Depreciation per Classification (\$)																						
20-yr SL	2,496,592	124,830	124,830	124,830	124,830	124,830	124,830	124,830	124,830	124,830	124,830	124,830	124,830	124,830	124,830	124,830	124,830	124,830	124,830	124,830	124,830	
30-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
37-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
50-yr SL	1,950,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	
Major Maintenance		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Annual Depreciation	3,276,592	163,830	163,830	163,830	163,830	163,830	163,830	163,830	163,830	163,830	163,830	163,830	163,830	163,830	163,830	163,830	163,830	163,830	163,830	163,830	163,830	
Major Maintenance																						
Timing of Spending																						
Occurrence 1		0	0	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	
Occurrence 2		0	0	0	0	0	0	0	0	0	1	2	3	4	5	6	7	8	9	10	11	
Occurrence 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	3	4	5	6	
Occurrence 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	
Depreciation Classification																						
Year	30-yr SL	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Depreciation Schedule		0.00%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Depreciation Expense																						
	Expense	Depreciation Amount																				
Occurrence 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Occurrence 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Occurrence 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Occurrence 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Net Book Value																						
Beginning Balance		0	4,282,763	4,118,933	3,955,104	3,791,274	3,627,444	3,463,615	3,299,785	3,135,955	2,972,126	2,808,296	2,644,467	2,480,637	2,316,807	2,152,978	1,989,148	1,825,318	1,661,489	1,497,659	1,333,830	
Original Book Value		4,446,592	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Plus: Major Maintenance		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Less: Depreciation		(163,830)	(163,830)	(163,830)	(163,830)	(163,830)	(163,830)	(163,830)	(163,830)	(163,830)	(163,830)	(163,830)	(163,830)	(163,830)	(163,830)	(163,830)	(163,830)	(163,830)	(163,830)	(163,830)	(163,830)	
Net Book Value		4,282,763	4,118,933	3,955,104	3,791,274	3,627,444	3,463,615	3,299,785	3,135,955	2,972,126	2,808,296	2,644,467	2,480,637	2,316,807	2,152,978	1,989,148	1,825,318	1,661,489	1,497,659	1,333,830	1,170,000	

Nova Scotia COMFIT Model		In-Stream Tidal
Assumptions		Notes:
General Inflation Factor (revenue and expenses)	1.92%	From NSPI 2009 IRP Update
Capital Costs (Uses of Funds)		
Development	\$950,000	
Equipment & Installation	\$3,335,000	
Interconnection	\$260,000	
Reserves		
Up-Front Maintenance	\$37,500	(Half of year-one O&M)
Working Capital	\$75,518	(Half of year-one expenses)
Debt Service Reserve	\$0	(Half of year-one debt service.)
Financing		
Debt Closing Costs & Fees	\$0	(Summed from below)
Equity Closing Costs & Fees	\$201,600	
Interest During Construction	\$179,750	
Total Project Cost	\$5,039,368	
Total Project Cost (\$/kW)	\$10,079	
Initial Reserve Account Sizing		
Upfront Maintenance (months of Year 1 O&M)	6	
Working Capital (months of Year 1 OPEX)	6	
Debt Service Reserve (months of P&I)	6	
Capital Structure (Sources of Funds)		
Amount (\$)		
Grants (net value)	0	
Debt	0	
Equity	5,039,368	
Total Sources of Funds	5,039,368	
Amount (%)		
Grants	0.0%	
Debt	0%	
Equity	100%	
Total Sources of Funds	100.0%	
Grants:		
State and Federal Incentives	0	
State/Provincial Tax 1	0	
State/Provincial Tax 2	0	
Federal tax	0	
Net Value of Grants	0	
Debt Terms		
Amount	0	(Based on target debt/equity ratio)
Amortization period	15	
Interest Rate	8.00%	
Up-Front Fee (%)	1.00%	
Up-Front Fee (\$)	0	
Closing Costs	0	(5% of loan value)
Tax Depreciation Allocation		
% of Total Project Cost		
30% Double Declining	0.0%	
50% Double Declining	62.9%	95% of hard costs
20-yr SL	0.0%	
40-yr SL	0.0%	
Other	0.0%	
Non-Depreciable	37.13%	
Total	100.0%	
Amount Allocated		
30% Double Declining	0	
50% Double Declining	3,168,250	
20-yr SL	0	
40-yr SL	0	
Other	0	
Non-Depreciable	1,871,118	
Total	5,039,368	
Year One Depreciation		
Year One Percent	25.0%	(Based on the "half year rule")
Year One Amount	792,063	

Assumptions Worksheet: All		Synapse Exhibit M
Assumptions:		Notes:
Operating Inputs		
Net Generator Capacity (MW)	0.50	
Energy Production:		
Net Capacity Factor	37%	Net of plant availability and other loss factors.
Net Output in MWhs	1,621	
Annual Operating Expenses		
Annual Fuel Cost		
Fuel Required per Year (mmBtu)	0	
Initial year Fuel Price (\$/mmBtu)	0	
Annual O&M (expensed)	75,000	Escalates at inflation.
Site Maintenance	0	Escalates at inflation.
General & Administrative	1,000	Escalates at inflation.
Insurance	66,700	Escalates at inflation.
Land Lease	2,500	Access lease only.
Other	0	
Property Tax		
Project hard costs less interconnection	3,335,000	
Assessed Value (%)	5.00%	
Assessed Value (\$)	166,750	
Annual Decline in Assessed Value	1.00%	
Assessed Value Minimum %	0.00%	
Property Tax Rate	3.50%	
Revenue Assumptions		
Levelized Energy Price (\$/MWh)	698.00	
% of Levelized Rate Escalating @ Infl.	0.0%	
Other Revenues (increases with inflation)	0	
Return Metrics		
20-year Equity IRR		
Pre-Tax	18.35%	
After-Tax	15.01%	
Average Debt Service Coverage Ratio	#DIV/0!	
Minimum Debt Service Coverage Ratio	#DIV/0!	
Minimum Annual After-Tax Equity Net Benefits	675,567	
Tax Rates:		
Federal Income Tax	15.0%	
State/Provincial Income Tax		
Tax Rate 1		
Applicable Income (less than X)	400,000	
Tax Rate 1	4.5%	
Tax Rate 2 (for income greater than X)	16.0%	
Major Maintenance		
Replacement Occurs Every X Years	6	
Cost of Replacement (Year 0 Dollars)	62,500	
	50% Double	
Tax Depreciation Classification of Spending	Declining	
Book Depreciation Classification of Spending	30-yr SL	
Residual Value		
Residual Value (Net Book Value)	0	
Book Depreciation Classifications		
20-yr SL	100.0%	
30-yr SL	0.0%	
37-yr SL	0.0%	
40-yr SL	0.0%	
Non-Depreciable	0.00%	
Total	100.0%	
Amount Allocated		
20-yr SL	5,039,368	
30-yr SL	0	
37-yr SL	0	
40-yr SL	0	
Non-Depreciable	0	
Total	5,039,368	

Operating Year		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Generation (MWh)			1,621	1,621	1,621	1,621	1,621	1,621	1,621	1,621	1,621	1,621	1,621	1,621	1,621	1,621	1,621	1,621	1,621	1,621	1,621	1,621
Partial Income Statement																						
Revenue																						
Standard Offer Price (\$/MWh)																						
Fixed Price Component	100%	698.00	698.00	698.00	698.00	698.00	698.00	698.00	698.00	698.00	698.00	698.00	698.00	698.00	698.00	698.00	698.00	698.00	698.00	698.00	698.00	698.00
Escalating Price Component	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Standard Offer Price		698	698	698	698	698	698	698	698	698	698	698	698	698	698	698	698	698	698	698	698	698
Revenues From Energy Production		1,131,179	1,131,179	1,131,179	1,131,179	1,131,179	1,131,179	1,131,179	1,131,179	1,131,179	1,131,179	1,131,179	1,131,179	1,131,179	1,131,179	1,131,179	1,131,179	1,131,179	1,131,179	1,131,179	1,131,179	1,131,179
Other Revenues		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Revenue		2,170	2,390	2,610	2,830	3,050	3,270	2,170	2,416	2,663	2,910	3,156	3,403	2,170	2,446	2,723	2,999	3,275	3,552	2,170	2,170	2,170
Total Revenue		1,133,349	1,133,569	1,133,789	1,134,009	1,134,229	1,134,449	1,133,349	1,133,595	1,133,842	1,134,088	1,134,335	1,134,581	1,133,349	1,133,625	1,133,901	1,134,178	1,134,454	1,134,730	1,133,349	1,133,349	1,133,349
Expenses																						
Fuel Cost		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O&M		(75,000)	(76,440)	(77,908)	(79,403)	(80,928)	(82,482)	(84,065)	(85,680)	(87,325)	(89,001)	(90,710)	(92,452)	(94,227)	(96,036)	(97,880)	(99,759)	(101,674)	(103,627)	(105,616)	(107,644)	(107,644)
Site Maintenance		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
G&A		(1,000)	(1,019)	(1,039)	(1,059)	(1,079)	(1,100)	(1,121)	(1,142)	(1,164)	(1,187)	(1,209)	(1,233)	(1,256)	(1,280)	(1,305)	(1,330)	(1,356)	(1,382)	(1,408)	(1,435)	(1,435)
Insurance		(66,700)	(67,981)	(69,286)	(70,616)	(71,972)	(73,354)	(74,762)	(76,198)	(77,661)	(79,152)	(80,671)	(82,220)	(83,799)	(85,408)	(87,048)	(88,719)	(90,422)	(92,159)	(93,928)	(95,731)	(95,731)
Land Lease		(2,500)	(2,548)	(2,597)	(2,647)	(2,698)	(2,749)	(2,802)	(2,856)	(2,911)	(2,967)	(3,024)	(3,082)	(3,141)	(3,201)	(3,263)	(3,325)	(3,389)	(3,454)	(3,521)	(3,588)	(3,588)
Other		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Property tax		(5,836)	(5,778)	(5,720)	(5,661)	(5,603)	(5,544)	(5,486)	(5,428)	(5,369)	(5,311)	(5,253)	(5,194)	(5,136)	(5,078)	(5,019)	(4,961)	(4,902)	(4,844)	(4,786)	(4,727)	(4,727)
Total		(151,036)	(153,766)	(156,549)	(159,386)	(162,279)	(165,229)	(168,237)	(171,303)	(174,430)	(177,617)	(180,867)	(184,181)	(187,559)	(191,003)	(194,514)	(198,094)	(201,744)	(205,465)	(209,259)	(213,126)	(213,126)
EBITDA		982,312	979,803	977,240	974,622	971,949	969,219	965,112	962,292	959,412	956,471	953,468	950,401	945,790	942,622	939,387	936,083	932,710	929,265	924,090	920,222	920,222
Equity Return																						
Cash																						
EBITDA		982,312	979,803	977,240	974,622	971,949	969,219	965,112	962,292	959,412	956,471	953,468	950,401	945,790	942,622	939,387	936,083	932,710	929,265	924,090	920,222	920,222
Plus: Release of Debt Service Reserve		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus: Release of WC & Up-Front Maint Reserves		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	113,018	113,018
Plus: Release of Major Maintenance Reserves		0	0	0	0	0	68,735	0	0	0	0	0	77,043	0	0	0	0	0	86,356	0	0	0
Plus: Residual Value		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less: Major Maintenance Spending		0	0	0	0	0	(68,735)	0	0	0	0	0	(77,043)	0	0	0	0	0	(86,356)	0	0	0
Less: Major Maintenance Reserve Funding		(11,456)	(11,456)	(11,456)	(11,456)	(11,456)	(11,456)	(12,841)	(12,841)	(12,841)	(12,841)	(12,841)	(12,841)	(14,393)	(14,393)	(14,393)	(14,393)	(14,393)	(14,393)	0	0	0
Less: Principal		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less: Interest		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Cash		970,857	968,347	965,784	963,167	960,493	957,763	952,271	949,451	946,572	943,630	940,627	937,560	931,397	928,229	924,994	921,691	918,317	914,873	924,090	1,033,241	1,033,241
Equity Investment		(5,039,368)																				
Total Pre-Tax Equity Return		(5,039,368)	970,857	968,347	965,784	963,167	960,493	957,763	952,271	949,451	946,572	943,630	940,627	937,560	931,397	928,229	924,994	921,691	918,317	914,873	924,090	1,033,241
Pre-Tax Internal Rate of Return	18.35%																					
Taxable Income Benefit/(Liability)																						
EBITDA		982,312	979,803	977,240	974,622	971,949	969,219	965,112	962,292	959,412	956,471	953,468	950,401	945,790	942,622	939,387	936,083	932,710	929,265	924,090	920,222	920,222
Less: Interest		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less: Tax Depreciation		(792,063)	(1,188,094)	(594,047)	(297,023)	(148,512)	(108,623)	(54,312)	(27,156)	(13,578)	(6,789)	(3,394)	(40,219)	(20,109)	(10,055)	(5,027)	(2,514)	(1,257)	(43,806)	(21,903)	(10,952)	(10,952)
Taxable Income/(Loss)		190,250	(208,291)	383,193	677,599	823,437	860,596	910,800	935,136	945,834	949,682	950,073	910,182	925,680	932,567	934,360	933,570	931,453	885,459	902,187	909,271	909,271
Tax Benefit/(Liability)																						
State/Provincial 1		(8,561)	9,373	(17,244)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)
State/Provincial 2		0	0	0	(44,416)	(67,750)	(73,695)	(81,728)	(85,622)	(87,333)	(87,949)	(88,012)	(81,629)	(84,109)	(85,211)	(85,498)	(85,371)	(85,032)	(77,673)	(80,350)	(81,483)	(81,483)
Federal		(28,537)	31,244	(57,479)	(101,640)	(123,516)	(129,089)	(136,620)	(140,270)	(141,875)	(142,452)	(142,511)	(136,527)	(138,852)	(139,885)	(140,154)	(140,035)	(139,718)	(132,819)	(135,328)	(136,391)	(136,391)
Total Tax Benefit/(Liability)		(37,099)	40,617	(74,723)	(164,056)	(209,266)	(220,785)	(236,348)	(243,892)	(247,209)	(248,401)	(248,523)	(236,156)	(240,961)	(243,096)	(243,651)	(243,407)	(242,750)	(228,492)	(233,678)	(235,874)	(235,874)
Equity Investment		(5,039,368)																				
Total After-Tax Equity Return		(5,039,368)	933,758	1,008,964	891,061	799,111	751,228	736,979	715,923	705,559	699,363	695,229	692,104	701,404	690,436	685,134	681,343	678,284	675,567	686,380	690,412	797,367
After-Tax Internal Rate of Return	15.01%																					

Nova Scotia COMFIT Model

Tidal Cash Flow Worksheet: Bottom

Synapse Exhibit M

Operating Year		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Debt																						
Loan Balance	8.00%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Principal		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Annual payment		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Debt Service Coverage Ratio																						
EBITDA		982,312	979,803	977,240	974,622	971,949	969,219	965,112	962,292	959,412	956,471	953,468	950,401	945,790	942,622	939,387	0	0	0	0	0	0
Less: Major Maintenance Reserve Funding		(11,456)	(11,456)	(11,456)	(11,456)	(11,456)	(11,456)	(12,841)	(12,841)	(12,841)	(12,841)	(12,841)	(12,841)	(14,393)	(14,393)	(14,393)	0	0	0	0	0	0
Cash Available for Debt Service		970,857	968,347	965,784	963,167	960,493	957,763	952,271	949,451	946,572	943,630	940,627	937,560	931,397	928,229	924,994	0	0	0	0	0	0
P&I		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Debt Service Coverage Ratio		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!						
Average	#DIV/0!																					
Minimum	#DIV/0!																					
Reserve Accounts																						
Reserves Funded As Part of Capital Cost																						
Beginning Balance	0	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018
Up-Front Maintenance Reserve	37,500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(37,500)
Working Capital	75,518	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(75,518)
Debt Service Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	113,018	0
Major Maintenance Reserve Funded Through Operations																						
Beginning Balance	0	11,456	22,912	34,367	45,823	57,279	0	12,841	25,681	38,522	51,362	64,203	0	14,393	28,785	43,178	57,570	71,963	0	0	0	0
Funding	11,456	11,456	11,456	11,456	11,456	11,456	12,841	12,841	12,841	12,841	12,841	12,841	12,841	14,393	14,393	14,393	14,393	14,393	14,393	0	0	0
Release of Funds	0	0	0	0	0	(68,735)	0	0	0	0	0	(77,043)	0	0	0	0	0	0	(86,356)	0	0	0
Ending Balance	11,456	22,912	34,367	45,823	57,279	0	12,841	25,681	38,522	51,362	64,203	0	14,393	28,785	43,178	57,570	71,963	0	0	0	0	0
Major Maintenance Costs																						
Occurrence 1	68,735	0	0	0	0	0	68,735	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 2	77,043	0	0	0	0	0	0	0	0	0	0	0	77,043	0	0	0	0	0	0	0	0	0
Occurrence 3	86,356	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	86,356	0	0	0
Occurrence 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Major Maintenance Funding																						
Occurrence 1	68,735	11,456	11,456	11,456	11,456	11,456	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Occurrence 2	77,043	0	0	0	0	0	0	12,841	12,841	12,841	12,841	12,841	12,841	0	0	0	0	0	0	0	0	0
Occurrence 3	86,356	0	0	0	0	0	0	0	0	0	0	0	0	14,393	14,393	14,393	14,393	14,393	14,393	0	0	0
Occurrence 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest on Reserves		2,170	2,390	2,610	2,830	3,050	3,270	2,170	2,416	2,663	2,910	3,156	3,403	2,170	2,446	2,723	2,999	3,275	3,552	2,170	2,170	2,170
Property Tax Calculation																						
Original Assessed Value		166,750	166,750	166,750	166,750	166,750	166,750	166,750	166,750	166,750	166,750	166,750	166,750	166,750	166,750	166,750	166,750	166,750	166,750	166,750	166,750	166,750
Annual Decline in Assessed Value		100.0%	99.0%	98.0%	97.0%	96.0%	95.0%	94.0%	93.0%	92.0%	91.0%	90.0%	89.0%	88.0%	87.0%	86.0%	85.0%	84.0%	83.0%	82.0%	81.0%	81.0%
Annual Assessed Value		166,750	165,083	163,415	161,748	160,080	158,413	156,745	155,078	153,410	151,743	150,075	148,408	146,740	145,073	143,405	141,738	140,070	138,403	136,735	135,068	135,068
Property Tax Rate		3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Property Tax Expense		5,836	5,778	5,720	5,661	5,603	5,544	5,486	5,428	5,369	5,311	5,253	5,194	5,136	5,078	5,019	4,961	4,902	4,844	4,786	4,727	4,727

Operating Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
Calendar Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	
Tax Depreciation																						
Calendar Year Depreciation per Classification (%)																						
30% Double Declining		30.00%	21.00%	14.70%	10.29%	7.20%	5.04%	3.53%	2.47%	1.73%	1.21%	0.85%	0.59%	0.42%	0.29%	0.20%	0.14%	0.10%	0.07%	0.05%	0.03%	
50% Double Declining		50.00%	25.00%	12.50%	6.25%	3.13%	1.56%	0.78%	0.39%	0.20%	0.10%	0.05%	0.02%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20-yr SL		2.50%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	
40-yr SL		1.25%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	
Other		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Calendar Year Depreciation per Classification (\$)																						
Year One Capital Cost Allocation	792,063	792,063	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
30% Double Declining	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
50% Double Declining	2,376,188	0	1,188,094	594,047	297,023	148,512	74,256	37,128	18,564	9,282	4,641	2,320	1,160	580	290	145	73	36	18	9	5	
20-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
40-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Major Maintenance		0	0	0	0	0	34,367	17,184	8,592	4,296	2,148	1,074	39,059	19,529	9,765	4,882	2,441	1,221	43,788	21,894	10,947	
Annual Depreciation	3,389,432	792,063	1,188,094	594,047	297,023	148,512	108,623	54,312	27,156	13,578	6,789	3,394	40,219	20,109	10,055	5,027	2,514	1,257	43,806	21,903	10,952	
Major Maintenance																						
Timing of Spending																						
Occurrence 1		0	0	0	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	
Occurrence 2		0	0	0	0	0	0	0	0	0	0	0	1	2	3	4	5	6	7	8	9	
Occurrence 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	3	
Occurrence 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Depreciation Classification																						
Year	50% Double	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Depreciation Schedule		0.00%	50.00%	25.00%	12.50%	6.25%	3.13%	1.56%	0.78%	0.39%	0.20%	0.10%	0.05%	0.02%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	
Depreciation Expense																						
	Expense	Depreciation																				
Occurrence 1	68,735	68,733	0	0	0	0	34,367	17,184	8,592	4,296	2,148	1,074	537	268	134	67	34	17	8	4	2	
Occurrence 2	77,043	76,893	0	0	0	0	0	0	0	0	0	0	38,522	19,261	9,630	4,815	2,408	1,204	602	301	150	
Occurrence 3	86,356	75,561	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	43,178	21,589	10,794	
Occurrence 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	

Nova Scotia COMFIT Model

Tidal Depreciation Worksheet: Bottom

Synapse Exhibit M

Operating Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Calendar Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030

Book Depreciation

Calendar Year Depreciation per Classification (%)

[illegible]

Calendar Year Depreciation per Classification (\$)

20-yr SL	5,039,368	251,968	251,968	251,968	251,968	251,968	251,968	251,968	251,968	251,968	251,968	251,968	251,968	251,968	251,968	251,968	251,968	251,968	251,968	251,968	251,968
30-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40-yr SL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Major Maintenance		0	0	0	0	0	34,367	17,184	8,592	4,296	2,148	1,074	39,059	19,529	9,765	4,882	2,441	1,221	43,788	21,894	10,947
Annual Depreciation	5,260,555	251,968	251,968	251,968	251,968	251,968	286,336	269,152	260,560	256,264	254,116	253,042	291,027	271,498	261,733	256,851	254,410	253,189	295,756	273,862	262,915

Major Maintenance

Timing of Spending

[illegible]

Depreciation Classification

[illegible]

Depreciation Expense

[illegible]

Net Book Value

Beginning Balance	0	4,787,400	4,535,431	4,283,463	4,031,495	3,779,526	3,561,925	3,292,773	3,032,213	2,775,948	2,521,832	2,268,790	2,054,806	1,783,308	1,521,575	1,264,724	1,010,315	757,126	547,725	273,862
Original Book Value	5,039,368	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus: Major Maintenance		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less: Depreciation	(195,968)	(251,968)	(251,968)	(251,968)	(251,968)	(266,336)	(269,152)	(260,560)	(256,264)	(254,116)	(253,042)	(291,027)	(271,498)	(261,733)	(256,851)	(254,410)	(253,189)	(273,862)	(295,756)	(262,915)
Net Book Value	4,787,400	4,535,431	4,283,463	4,031,495	3,779,526	3,561,925	3,292,773	3,032,213	2,775,948	2,521,832	2,268,790	2,054,806	1,783,308	1,521,575	1,264,724	1,010,315	757,126	547,725	273,862	10,947