UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 1 to all Applicants

Please provide your proposed organizational chart for the project development and construction phases as well as for the operation and maintenance phase, showing the various functions (including those functions listed in 4.1 of the Filing Requirements) and the reporting structure. Please include in these charts the names of members of the proposed management team (including the project manager / lead) and technical team who would be leading each function.

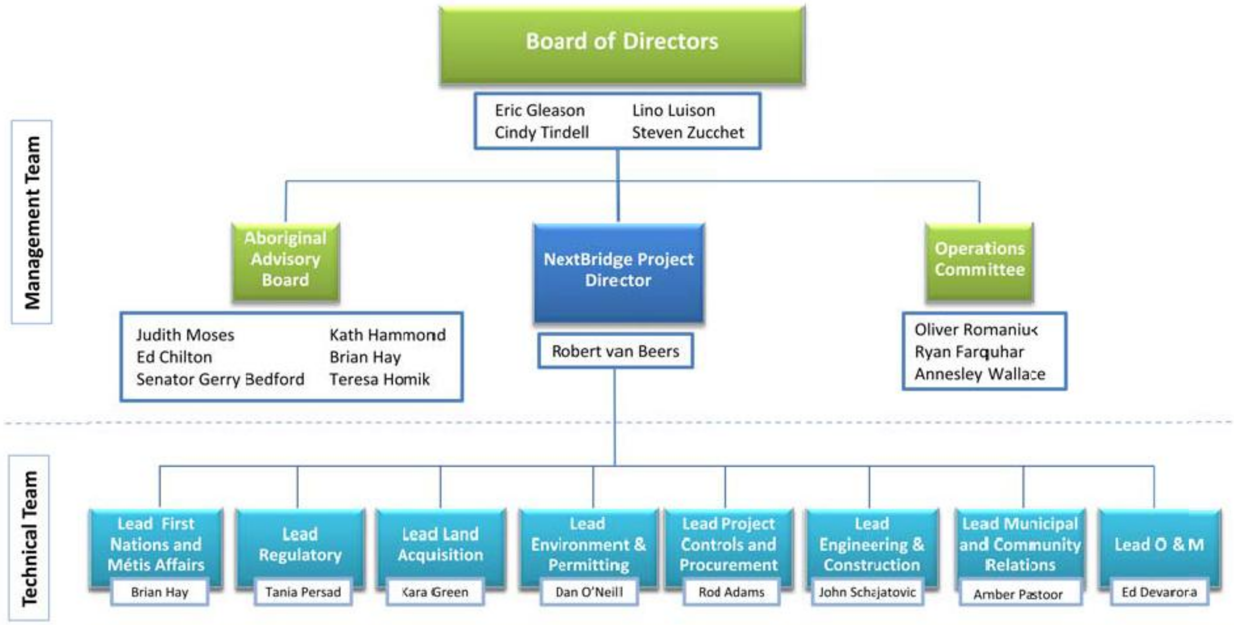
Response:

Figure 4 from NextBridge's Application (included below) shows the proposed organizational structure for the development, construction, and operations and maintenance phases of the project. The figure includes the names of the members of the proposed management team and technical team. The resumés for these individuals are included in Appendix 3 of NextBridge's application.

As described in Section 2.2 of NextBridge's application, the responsibility for day-to-day management of the project rests with the Ontario-based Project Director who oversees the technical team and reports to the NextBridge Board of Directors. The organization structure includes an Aboriginal Advisory Board and an Operations Committee. These committees report to the Board of Directors and are also accessible to the technical teams directly as needed.

The same organization structure will be used in all three phases of the project to ensure a seamless transition from phase to phase and continuity in project decision-making. However, throughout each phase there will be a varying level of activity from certain groups. For example, the O&M technical team will be involved early on in the planning process, but not heavily involved again until commissioning approaches.

The roles and responsibilities of each of the positions shown in the organizational chart are described in greater detail in NextBridge's application, in Section 2.2 for the management team and 4.2 for the technical team.



The following table maps the functions listed in Section 4.1 of the Filing Requirements to the proposed organizational chart shown above.

Section 4.1 Filing Requirements	**NextBridge's Proposed Organization Structure**
Design	Lead Engineering & Construction
Engineering	Lead Engineering & Construction
Material and equipment procurement	Lead Project Controls and Procurement
Licensing and permitting	Lead Environment & Permitting
Completion of environmental assessment and other regulatory approvals	Lead Environment & Permitting
Consultations with First Nation and Métis, and other communities	Lead First Nations and Métis Affairs
Construction	Lead Engineering & Construction
Operations and maintenance	Lead O&M
Project management	NextBridge Project Director

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 2 to all Applicants

For the chosen project manager / lead, please confirm if this person will be dedicated to this project and describe this person's experience in managing similar projects.

Response:

The proposed Project Director, Robert van Beers, will be dedicated to this project and located in Ontario. As described in his resumé in Appendix 3 of the NextBridge application, Mr. van Beers is the Senior Director of Power Transmission at Enbridge. For eight years, he was Chief Development Officer (later CEO) of Tonbridge Power Inc., Canada's only publicly traded independent transmission company. Tonbridge Power was the developer of the Montana-Alberta Tie-Line (MATL) project, a 230 kV AC project that will provide the only direct connection between the Alberta and U.S. power grids (the line will go into service later this year); the first cross-border merchant transmission line in North America. While at Tonbridge Power, Mr. van Beers was the executive with most direct responsibility for MATL. He negotiated the engineering, procurement and construction management contracts; hired and oversaw all project staff; directed the regulatory and land acquisition strategy; reported to the Board of Directors on all project matters; maintained senior government, regulatory and stakeholder relationships; and was instrumental in securing construction financing. As CEO of Tonbridge Power, he led the sale of the business to Enbridge in 2011.

Mr. van Beers has been instrumental in shaping and developing the North American transmission landscape for almost 20 years. He has experience in a broad range of projects, including from his early role as an advisor to Trans-Elect in its establishment and later its acquisition of the transmission grid in Michigan from Consumers Energy; his role in advancing the *American Recovery and Reinvestment Act*'s Transmission Infrastructure Program; his advocacy at the U.S. Federal Energy Regulatory Commission on merchant transmission policy and his work on helping the evolution of the independent business model for transmission development.

Mr. van Beers also has extensive power sector experience in northern Ontario, having been the lead advisor to municipal distribution utilities in the region in advance of the liberalization of the Ontario Power market (in the late 1990s), helping these companies establish competitive affiliates, explore investment opportunities and forge partnerships with capital investors and energy service companies.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 3 to all Applicants

For the list of "key technical team personnel" provided in response to section 4.2 of the Filing Requirements, please provide the specific proposed project / O&M role for each member.

Response:

The following specific proposed project/O&M role for each key member of the technical team was provided in Section 4.2 of NextBridge's Application, and is copied here for convenience.

John Schajatovic, Lead Engineering & Construction
John Schajatovic is a Project Manager for NextEra Energy Resources responsible for early stage management within the Engineering and Construction Department of NEER. As the Lead for Engineering and Construction on this project, he will be responsible for the completion of the engineering design for the Project and ensuring it incorporates the necessary constructability considerations.

Eduardo DeVarona, Lead Operations and Maintenance
Eduardo DeVarona is Director of Operations at NextEra Energy Transmission, LLC. As the O&M Lead on this project, he will be responsible for developing the operations strategy for the facilities post Commercial Operations Date (COD). He will ensure that operational considerations are included in the development, engineering and construction phases. He will also develop an operating strategy which will include operations and maintenance staffing estimates, third party resource estimates and an O&M budget. He will ensure execution of the operating strategy during the pre-COD period and coordinate project commissioning activities with the construction team to ensure a successful transition to operations. In addition, he will coordinate with the Lead for Regulatory on this project in managing compliance with IESO market rules and reliability standards.

Brian Hay, Lead First Nation and Métis Affairs
Brian Hay is the Director of Aboriginal Relations for NextEra Energy Canada ULC and its associated companies. As the Lead for First Nation and Métis Affairs on this project, he will engage and consult with the affected First Nation and Métis communities to validate and further develop our Consultation Plan and our Participation Plan for the project. He will also be responsible for making recommendations to the Management Team related to First Nation and Métis consultation and participation. He will be available to interface regularly with First Nation and Métis communities and to respond to any questions and concerns that arise.

Tania Persad, Lead Regulatory
Tania Persad is the Senior Legal Counsel and Gas Distribution Compliance Officer with Enbridge Gas Distribution Inc. As the Lead for Regulatory on this project, she will be responsible for applications to the OEB for leave to construct and for approved rates once the facility is transitioned into service. In addition, she will manage obligations under the Transmission License with respect to new connections (as applicable), record keeping and reporting, and all other ongoing regulatory obligations. She will also be responsible for communications with and applications to the OEB about regulatory proceedings and requirements applicable to the project. She will coordinate NextBridge and external resources, as required, to develop regulatory applications and compliance mechanisms to ensure appropriate accounting, operations and oversight in accordance with applicable OEB orders, laws, regulations and guidelines.

Kara Green, Lead Land Acquisition
Kara Green is a Senior Land and Right-of-Way Specialist with Enbridge Pipelines Inc. As the Lead for Land Acquisition for this project, she will be responsible for constraints-based optimization of the route, collecting the information related to the land requirements along the selected route and managing the process for acquiring the necessary rights to the land for the purpose of executing the project. She will also work with the Environment & Permitting and Engineering & Construction Leads on this project on route planning and minimizing impact to affected parties along the route.

Dan O'Neill, Lead Environment & Permitting
Dan O'Neill is the Senior Environmental Analyst, Environment, Lands & Right of Way for Canadian Projects with Enbridge. As the Lead for Environment and Permitting for this project, he will be responsible for obtaining all project permits in accordance with the project schedule to allow for engineering and construction to proceed as planned. He will interface directly with the Ministry of Environment and other organizations to identify, review and address potential issues and implement resolutions as required. He will also be responsible for assisting in route planning to minimize environmental impact along the route.

Amber Pastoor, Lead Municipal and Community Relations

Amber Pastoor is a Senior Strategist, Stakeholder Relations with Enbridge Pipelines Inc. As the Lead for Municipal and Community Relations for this project, she will be responsible for developing and executing a public consultation program throughout the life of the project. This includes providing strategic stakeholder relations and public consultation counsel and expertise to the project team to fulfill all legal/regulatory requirements for public consultation. She will engage stakeholders early in the development planning process to learn about community interests and perspectives, and take those into account in decision-making; and will develop and maintain ongoing dialogue with stakeholders through all project stages to increase knowledge of the effects of its business activities, develop balanced standards and expectations, and seek solutions to problems.

Rod Adams, Lead Project Controls and Procurement

Rod Adams is Director, Business Services of NextEra Energy Transmission LLC. As the Lead for Project Controls and Procurement on this project, he will be responsible for the cost and schedule for the development phase, as well as third party contracts required. He will work closely with all the Technical Team Leads to ensure that the most current project information is communicated to the Project Director and Management Team. This role also involves identifying and communicating potential cost saving or schedule efficiency opportunities.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 4
to all Applicants

On a national and international basis, identify any and all transmission projects where the applicant, its partner(s), shareholder(s), affiliate(s) or other related entities (collectively referred to as the "Applicant") have commenced the construction of a new transmission line but which the Applicant has been unable to complete and/or bring into service. Please describe the reasons why the Applicant has been unable to complete the transmission line and/or bring it into service.

Response:

There are no new transmission lines which the applicant (including its partner(s), shareholder(s), affiliate(s) or other related entities) has been unable to complete and/or bring into service. All transmission projects currently under construction by the applicant are on track to come into service.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 5 to all Applicants

Please list the individuals that you plan to allocate to each of a) negotiating First Nation and Métis participation and b) conducting consultation with First Nation and Métis communities as delegated by the Crown. For each individual, please describe the individual's responsibilities on the team, relationship to the affected communities (if any), and relevant experience.

Response:

Direct community consultation and negotiation will be led by Brian Hay, who is well known to the communities identified by the Ontario Ministry of Energy through its May 31, 2011 letter to the Ontario Power Authority as communities to consult on the East-West Tie project. Mr. Hay has worked in particular with the Robinson Superior Treaty and Nishnawbe Aski Nation members, through more than 30 years of engagement in Aboriginal relations for various employers, including the Ontario Power Authority and Imperial Oil, the National Fur Institute, Canadian Trappers Association, United States Fish and Game Officers Association, The Métis Nation of the North West Territories and the Government of the North West Territories. Mr. Hay is currently the Director of Aboriginal Relations for NextEra Energy Canada.

NextBridge will direct and manage both its negotiation and its consultation program by means of an Aboriginal Advisory Board (AAB) composed of Mr. Hay (NextEra), Teresa Homik (Enbridge), Kath Hammond (Borealis), Gerry Bedford, Ed Chilton and Judith Moses. The responsibilities and relevant experience of the members of the NextBridge AAB are detailed at pages 24, 25, 30-31 of the NextBridge application, and in the resumes of AAB members included in Appendix 3 of the Application (pages 6-11).

In addition to the expert and experienced resources provided by the NextBridge AAB, Mr. Hay will engage day-to-day assistance using a combination of NextBridge internal staff and a suite of well-regarded and experienced consultants retained from among the following organizations, each of which has agreed to work with NextBridge if it is designated, subject to confirmation of availability and conflict of interest matters. NextBridge will engage one or more of these particular consultants in negotiations and consultations with particular communities with which they are most familiar and with whom they have established relationships.

- Angus Toulouse and Associates has direct knowledge of all potentially affected and interested communities as the company principal is a former Ontario Regional Chief.

- Robert Waldon, the Principal of Bedford Consulting and Associates has worked extensively with the Métis Nation of Ontario and local Métis communities throughout the region as well as consulting with NextEra on other projects.

- McLeod Wood Associates Inc. principals, Merv McLeod and Nancy Wood, are well regarded and experienced in working with many of the communities on the OEB list as well as with one competing proponent.

- Cindy Crowe Consulting, which is based in Thunder Bay, has worked directly with Red Rock, Fort William and other communities in the area on other projects.

- MPower North, headed by Marvin Pelletier is also based in Thunder Bay and has worked with Fort William First Nation and most of the economic developers among the Robinson Superior Treaty members.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 6 to all Applicants

If you are selected as the designated transmitter, will the First Nation and Métis communities identified by the Ministry of Energy in its letter to the Ontario Power Authority ("OPA") dated May 31, 2011, and possibly other affected and interested First Nation and Métis communities, be given an equal opportunity to participate in the project? Will all affected (or interested) First Nation and Métis communities be given equal opportunity for **all forms** of participation in the project (e.g. employment opportunities, equity participation)?

Response:

In considering this interrogatory, NextBridge has interpreted the term "participation" to encompass both :

a. "economic participation" (options for which include; i) equity participation on a preferred or common basis; ii) lump sum payment; and iii) a rate "adder" concept, all as detailed in Appendix 5 to NextBridge's application); and

b. other forms of participation (including; i) employment opportunities; ii) education and training; iii) procurement and contracting opportunities; iv) strategic and community investment; and v) access to supporting programs, all as detailed in Chapter 3 of NextBridge's application).

This interpretation is consistent with the comments of the Board at page 8 of its Phase 1 Decision (paragraph 2), where the Board stated:

> *"Participation" can mean many things, and the Board will not restrict its consideration to any particular type of participation.*

NextBridge agrees that affected First Nation and Métis communities should be given opportunities to participate in the project. The specific form of participation for each affected community may differ, and priority consideration for participation would be given to those communities most affected.

Furthermore, as NextBridge states in Section 10 of its application, should a First Nation or Métis community that has not been previously engaged identify itself as interested NextBridge will engage with that group, at a minimum, to share information about the project.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 7 to all Applicants

Does a First Nation or Métis community need to be "affected" by the project, in order to participate, or can it participate if it is not affected but still interested?

Response:

Please refer to NextBridge's response to Board interrogatory 6 to all applicants in respect of the use of the term "participate" in the context of First Nation and Métis participation in the East-West Tie project.

NextBridge does not believe that a First Nation or Métis community necessarily needs to be "affected" by the project in order to participate in some fashion. However, as noted in response to Board interrogatory 6 to all applicants, NextBridge would give the First Nations and Métis communities that are most affected priority consideration for participation. For other communities that are not as affected but are interested in participating, there may be opportunities, depending on project needs and community capacity.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 8
to all Applicants

Have you (or an affiliate) assisted, or will you (or an affiliate) assist, a prospective First Nation and Métis equity participant by providing a loan, by arranging financing through an independent financial institution, or otherwise? If yes, please explain how.

Response:

As detailed in NextBridge's Application (see, for example, page 13), NextBridge intends to work with each First Nation and Métis community to determine its capacity for, and interest in, the different types of project participation available (such as those listed in response to Board interrogatory 6 to all applicants). NextBridge further believes that the approaches for participation by the First Nation or Métis communities ultimately selected for the project must be financially appropriate for them, as well as NextBridge and Ontario ratepayers.

To the extent agreed by all parties involved in the context of broader discussions and negotiations regarding project participation, NextBridge could assist participating First Nation and Métis communities in their efforts to obtain government loan guarantees and/or provide advice, resources and expertise to them in arranging financing through independent financial institutions and/or capital markets.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 9
to all Applicants

Have you undertaken, or will you undertake, an assessment to quantify the potential impacts on the affected First Nation and Métis communities, the amount of which could be counted toward the participating community's equity contribution?

Response:

The impact of the project on any particular community will be evaluated during consultations with that community. The nature and extent of the impact on that community, and the extent to which such impact can be reasonably and acceptably mitigated, will be considered. To the extent that unmitigated impacts are compensated, a community may elect to apply such compensation toward its equity contribution, if it is participating through an equity, or equity-type investment in the project.

As noted in response to Board interrogatory 6 to all applicants, equity contribution is one of a number of potential options for First Nations and Métis participation in the East-West Tie project. At present, the extent to which equity participation is desired by, or appropriate for, any particular community is unknown. This will become clear only after discussions with each community and consideration by affected parties of the community's capacity for, and interest in, the different types of project participation available.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 10 to all Applicants

For those who propose to have or have equity participation with First Nation or Métis partners, how do you anticipate this participation will affect your credit rating, if at all?

Response:

If there is equity participation by First Nation or Métis partners, it is not expected to have any negative impact on the creditworthiness of either the project entity or the NextBridge partners.

As discussed in section 5.2 of our application, NextBridge does not, as a newly formed entity, have an independent credit rating. It does, however, have full support from the three NextBridge partners, each of which has an investment grade credit rating:

a. NextEra Energy Capital Holdings, Inc. has a credit rating of A- from Standard and Poor's (S&P), Baa1 from Moody's and A- from Fitch Ratings.

b. Enbridge has a credit rating of A- from S&P, Baa1 from Moody's and A (Low) from Dominion Bond Rating Service (DBRS).

c. OMERS Administration Corporation has a credit rating of AAA from S&P.

The three NextBridge partners are each well-capitalized entities. In aggregate they hold assets exceeding $100 billion in value. Considering the size of the project as compared to this aggregate asset base, equity participation by First Nation or Métis partners will not adversely affect NextBridge's financial resources or the respective creditworthiness and ratings of each partner.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 11 to all Applicants

With respect to First Nation and Métis participation issues, please identify any First Nation and Métis communities you have initiated contact with, those you have met with, and those you have existing arrangements to meet with.

Response:

Prior to submission of its application, NextBridge sent letters of introduction to all fourteen First Nations and four Métis organizations listed in the letter sent by the Minister of Energy to the Ontario Power Authority dated May 30, 2011. NextBridge's letters describe NextBridge, its three partner organizations, and its intent to apply for designation to develop the project. Subsequently, a representative of NextBridge's First Nation and Métis Relations team contacted the Band offices of six First Nations most directly affected by the project (Fort William, Red Rock, Pays Platt, Pic River, Pic Mobert and Michipicoten) to request copies of their consultation protocols. NextBridge further has had informal, in-person conversations with members of various communities over the course of several months. NextBridge also has operated under the understanding that during the Application period, formal contact should be deferred until the Board issues its order on designation. This approach is consistent with the Energy Minister's May 31, 2011 letter to the OPA regarding the OPA's role in consultation *"during the period prior to any Ontario Energy Board (Board) transmitter designation"*.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 12
to all Applicants

Does your Consultation Plan treat engagement with First Nations and Métis communities, whose traditional territories will be crossed by the proposed East-West Tie route, on an equivalent basis? Where there are differences in the proposed engagement between First Nations and Métis communities please explain and provide justification for the difference.

Response:

NextBridge will engage with each First Nation and Métis community in the manner with which they are most amenable, in an equitable and consistent manner. This is reflected in the existing First Nation and Métis consultation policies of NextEra and Enbridge. NextBridge will be guided by the consultation protocols and preferences of each community with which it deals. NextBridge does not distinguish in application of its consultation policies as between First Nations communities on the one hand, and Métis communities on the other.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 13 to all Applicants

Please outline and provide examples of relevant experience the applicant has in undertaking procedural aspects of consultation with Métis communities in the context of the development, construction or operation of a transmission line or other large scale construction projects.

Response:

As the applicant is a newly formed entity, it will engage the expertise of its three partner organizations in undertaking procedural aspects of consultation with Métis communities.

For example, the following summarizes the Métis consultation program undertaken by Enbridge on the Alberta Clipper, Southern Lights and Line 4 Extension Pipeline Projects:

> Alberta Clipper is a 1,607 km (1,000 mile) pipeline between Hardisty, Alberta and Superior, Wisconsin that went into service in the fall of 2010. The Southern Lights diluent delivery system came into service July 2010 and carries product through 2,556-km (1,588 miles) of pipeline originating near Chicago, Illinois and terminating in Edmonton, Alberta. The Line 4 Extension Project which extended Enbridge's existing Line 4 Pipeline by 180 km between Hardisty and Edmonton, was put into service in May 2009.
>
> For all three of these projects, Enbridge initiated and undertook consultations individually with four regions of the Métis Nation of Saskatchewan (MNS), starting with the provision of project information materials followed by face-to-face meetings and telephone calls to answer questions and determine community impacts. Later in the projects, the MNS became the lead organization representing all Métis in Saskatchewan. As a result, Enbridge conducted similar consultation activities with the MNS, which included discussions on employment, economic participation and community investment.

> In addition, Enbridge initiated and undertook consultations with the Métis Nation of Alberta Regions 2, 3 and 4 and the Manitoba Métis Federation, who acted on behalf of the Manitoba Métis community. Consultation topics included environmental matters and economic participation opportunities in the projects. In Alberta, project open houses were held in three locations where members of the respective Métis Regional organizations could receive project information and discuss concerns.

Another example, based in Alberta, is Enbridge's consultation history with Métis communities in the Athabasca Region of Alberta. Enbridge has engaged in consultation with the Conklin Métis Local 193 on at least six major pipeline and infrastructure projects over the past five years resulting in strong, mutually beneficial relationships and ongoing support by the Métis community of Enbridge projects and operations.

NextEra is currently developing eight wind energy facilities totaling over 600 MW in South Western Ontario. As an integral part of the process for developing these projects, NextEra is undertaking engagement and consultation with 17 First Nation and 4 Métis communities. In its consultation with the Métis communities, NextEra is engaging directly with the three Regional Councils as well as the Métis Nation of Ontario, with a view to entering into a collective Capacity Agreement in the second quarter of 2013, which agreement will form the basis for a subsequent Impact/Community Benefit Agreement.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 14
to all Applicants

Is the applicant or any of its affiliates/partners aware of any outstanding claims, applications, reviews or other proceeding brought against it (them), as transmitter or otherwise, by a First Nation or Métis community who disputes the use or proposed use of land, including disputes related to consultation or accommodation, compensation, mitigation, remedial measures, or other similar claims? If so, please identify and describe.

Response:

NextBridge comprises a partnership between NextEra, Enbridge Inc. and Borealis. For the purposes of this response, NextBridge has assumed that the OEB is referring to court applications or other proceedings initiated by First Nations or Métis communities, as opposed to interventions in regulatory proceedings initiated by applicants related to NextBridge and where project impacts may be discussed.

Neither the applicant nor any of its affiliates/partners is aware of any outstanding claims brought against any of them by a First Nation or Métis community that disputes the use or proposed use of land as referred to above.

Enbridge adds that should the OEB intend a wider view of the terms “claim” or “proceeding” extending to participant involvement in hearings, the following summary related to Northern Gateway may apply:

> Enbridge’s Northern Gateway Pipeline Application is currently being assessed in a regulatory process before a Joint Review Panel composed of members of the National Energy Board and Canadian Environmental Assessment Agency.
>
> Currently, there are First Nations or Aboriginal Groups from locations across the proposed Northern Gateway pipeline corridor from Bruderheim, Alberta, to Kitimat, B.C., and additional First Nations along the marine transportation routes that have intervened in the Joint Review Panel hearings on the project. Their concerns are varied and may be accessed on the website of the National Energy Board, under the Northern Gateway Project tab.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 15 to all Applicants

Has your proposed design has been utilized successfully in terrain and weather conditions similar to that of Northern Ontario? If not, please comment on the potential risks of your proposed design with respect to its use in Northern Ontario.

Response:

NextBridge's Recommended Plan for the Ontario East-West Tie project proposes the use of guyed lattice structures specifically to address and respond to the challenging terrain and weather conditions of Northern Ontario. Guyed lattice structures have been successfully used for transmission lines by BC Hydro and Manitoba Hydro, and are currently being installed by Hydro Quebec, as the information attached to this response illustrates.

In addressing terrains like those in British Columbia, Quebec, Manitoba, and Northern Ontario, the use of guyed structures:

1. Eliminates the need for uneven legs customized for each location in rugged terrain.

2. Facilitates helicopter construction, and minimizes the size of construction equipment required, due to lighter weight.

Combined, these advantages allow the project team to field adjust structure locations and avoid construction delays.

Example Transmission Projects Using Guyed Transmission Towers

Summary

Projects Currently In Service

1. **Herblet Lake to The Pas (Ralls Island) Transmission Line**
   Manitoba Hydro
   230-kV AC, 160 km, Guyed-Y Format
   In Service September 2011

2. **Gilliam to Churchill Transmission Line**
   Manitoba Hydro and Provincial Govt.
   138-kV AC, 270 km, Guyed-Y Format
   In Service April 1987

3. **Skeena to Amax Transmission Line**
   BC Hydro
   138-kV AC, Approximately 100 km, Guyed-Y
   Estimated pre-1980

Projects Currently in Construction or Development

4. **Romaine-2-Arnaud Transmission Line (Currently under Construction)**
   Hydro Quebec
   735-kV AC, 265 km, Guyed-Y Format
   In Service Expected 2014

5. **Northwest Transmission Line (Currently under Construction)**
   BC Hydro
   287-kV AC, 340 km, Guyed-Y Format
   In Service Expected 2014

6. **Bipole III Transmission Line**
   Manitoba Hydro
   500-kV DC Bipole, 1300+ km, Guyed-Mast Format
   In Service Expected Oct 2017

7. **BlackRock Metals Mining Electrical Service**
   Hydro Quebec
   161-kV, 25 km, Guyed-V Format
   In Service Expected Spring 2014

Particulars

1. **Herblet Lake to The Pas Ralls Island Transmission Line**
230-kV, 160 km
In service Sept 2011
Manitoba Hydro

Youtube video of installation:
http://www.youtube.com/watch?feature=player_detailpage&v=s2Gb4TtTCNQ

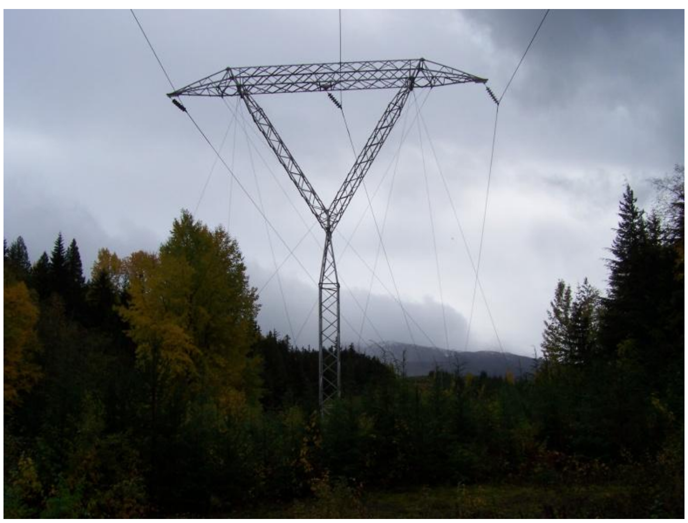
Reference:
http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2010_2012/Appendix_82.pdf

2. **Gilliam to Churchill Transmission Line**
138-kV, 270 km
In service Apr 1987
Manitoba Hydro and Provincial Govt.

This transmission line, from Gillam to Churchill permitted the retirement of large diesel generators in the town of Churchill. A reduction in the cost of power, coupled with an increase in supply was important to the continued development of the town and port. This is a 138 kV guyed tower line running through many areas of continuous permafrost.

The line was energized in April 1987. Constructed over three winters, the 270 km transmission line was jointly funded by Manitoba Hydro and the federal and provincial governments for $35.6 million.

3. **Skeena to Amax Transmission Line**
BC Hydro
138-kV AC, Approximately 100 km
Estimated pre-1980



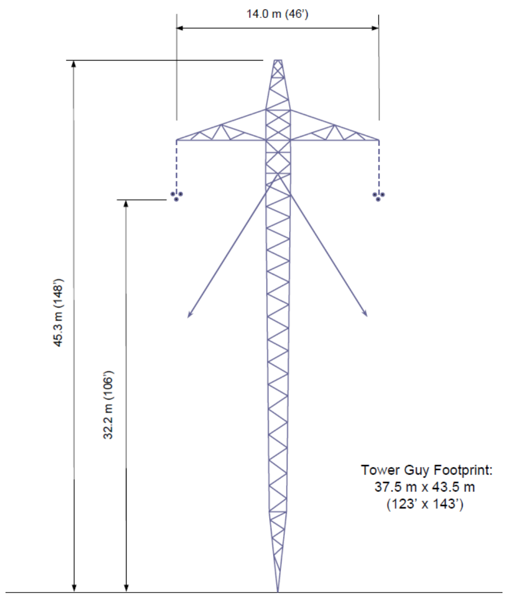
4. **Romaine-2-Arnaud Transmission Line (Currently under Construction)**
Hydro Quebec
735-kV AC, 265 km, Guyed-V Format
In Service Expected 2014

Please see attached.

5. **Northwest Transmission Line**
287-kV AC, 340 km
In service Expected 2014
BC Hydro

http://www.bchydro.com/energy_in_bc/projects/ntl.html

6. **Bipole III**
500-kV DC Bipole, 1300+ km
In service Expected Oct 2017
Manitoba Hydro



Project Description

The Bipole III transmission project involves the construction of:
a 500-kilovolt HVDC transmission line linking the northern power generating complex on the Lower Nelson River with the conversion and delivery system in southern Manitoba;

- 2 new converter stations – one in northern Manitoba northeast of Gillam (Keewatinoow) and one east of Winnipeg at the Riel Station site;
- 2 ground electrodes – one at each converter station;
- additional 230 kV transmission line interconnections in the north to tie the new converter station into the existing northern AC system.

The Bipole III ± 500 kV HVDC transmission line will:

1. originate at a Keewatinoow converter station site near the proposed Conawapa Generating Station site;
2. travel west and south towards The Pas;
3. travel south, staying west of Lake Winnipegosis and Lake Manitoba;
4. pass south of Portage la Prairie and Winnipeg to terminate at the Riel Converter Station site, in the RM of Springfield.

The preliminary preferred route is approximately 1,364 km in length.
Bipole III transmission line will be strung on steel tower structures on a 66 m wide right-of-way, with an average tower spacing of approximately 480 m resulting in 3 to 4 towers per mile. In agricultural areas, self-supporting towers will be used to reduce effects on agricultural operations. Guyed towers will be used in forested areas and other areas that are compatible with the use of this tower type.

http://www.hydro.mb.ca/projects/bipoleIII/guyed_suspension_tower.pdf
Screen clipping taken: 3/21/2013 11:27 AM

View a self-supporting suspension tower. (open new window)
View a guyed suspension tower. (open new window)

Pasted from <http://www.hydro.mb.ca/projects/bipoleIII/description.shtml>

Anticipated ISD for Bipole III is October 2017
Reference:
http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2010_2012/Appendix_82.pdf

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Filed: 2013-03-28
EB-2011-0140
Board #15 (All Applicants)
Attachment 2

Hydro Québec
TransÉnergie

161-kV BlackRock Metals Mining Property Electricity Service

PUBLIC CONSULTATION • September 2012

Mining project in the Nord-du-Québec region

BlackRock Metals Inc. wishes to carry out a mining project east of Lac Chibougamau, about 30 km southeast of the town of Chibougamau and 60 km east of the community of Oujé-Bougoumou.

The current project consists of building a 161-kV single-circuit power line, about 25 km long, tapping off circuit 1627 to connect the future BlackRock Metals substation to Hydro-Québec TransÉnergie's transmission system. The electrical load from all BlackRock Metals mining property facilities will be about 44 MW.

Commissioning of this power line is planned for spring 2014. After project completion, Hydro-Québec plans to dismantle part of the existing line (circuit 1627) between Obatogamau substation and the tap-off. Obatogamau substation will also be dismantled as part of another project.

Hydro-Québec TransÉnergie has asked Hydro-Québec Équipement et services partagés to conduct the draft-design studies for the planned supply of the BlackRock Metals mining property.

Environmental studies

Hydro-Québec Équipement et services partagés is carrying out environmental inventories and technical surveys in the study area to acquire knowledge about the host environment. These are done based on a clearly established procedure that includes documentary research and site visits and also take into account stakeholder concerns. An environmental impact statement will be submitted in fall 2012 to the Ministère du Développement durable, de l'Environnement et des Parcs du Québec in order to obtain the required permits to carry out the project.

Tower types and rights-of-way

The projected line will be supported by guyed steel towers. These towers are between 36 m and 55 m tall. The average span of 500 m, for 55-m high towers, will keep impact on the land to a minimum. The total width of the right-of-way to be cleared will be about 50 m for suspension towers and 80 m for dead-end towers.

Proposed routes

Based on the inventory of the biophysical and human environments and the landscape, Hydro-Québec used a number of siting criteria to determine the possible line routes:

- Respect of technical constraints
- Avoidance of environmentally sensitive areas
- Concerns of land users
- Integration into the landscape

Hydro-Québec has selected two routes:

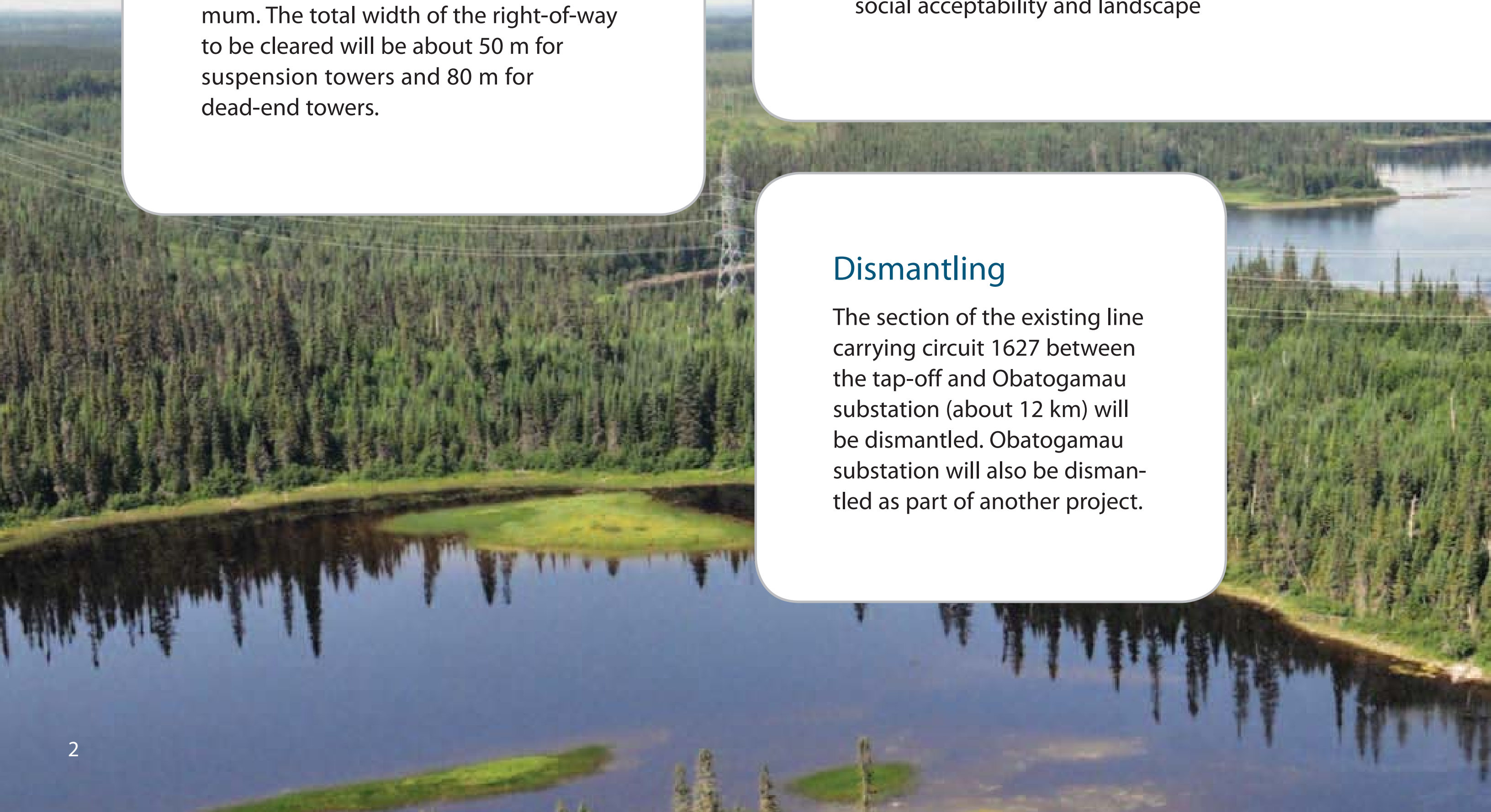
- **Route A** is 25.4 km long and is located in the northwestern part of the study area. It avoids many wetlands, it is far from areas frequented by land users and will integrate well into the landscape.
- **Route B** is 26.4 km long and is located in the middle of the study area. It follows a logging road, is more easily accessible and would allow infrastructure to be grouped together. However, it creates a greater impact on wetlands and is more visible. In terms of technical criteria, it is comparable to Route A.

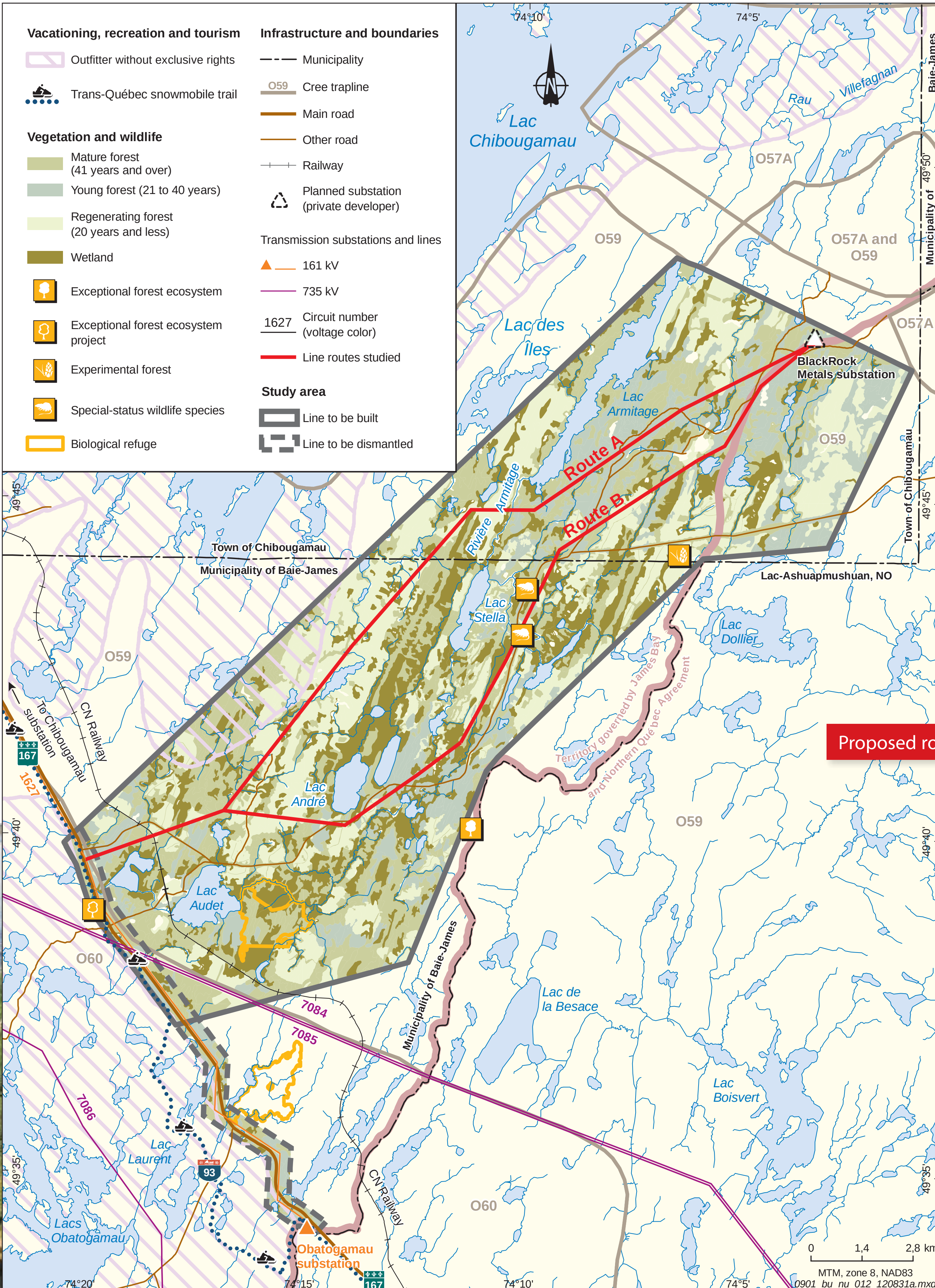
The routes will be compared based on the following main criteria:

- Economic: cost
- Technical: length, angles and access
- Environmental: sensitive areas crossed, land use, social acceptability and landscape

Dismantling

The section of the existing line carrying circuit 1627 between the tap-off and Obatogamau substation (about 12 km) will be dismantled. Obatogamau substation will also be dismantled as part of another project.





Proposed routes

Project schedule

DRAFT DESIGN

General information	Spring 2012
Information and consultation	Summer 2012
Information on route selected	Fall 2012

PROJECT

Filing of environmental impact statement	Fall 2012
Permitting	Summer 2013
Construction	Winter 2013-2014
Commissioning	Spring 2014

www.hydroquebec.com/projects

Public participation

Favorable reception from local communities is an essential condition for Hydro-Québec projects. To ensure that their concerns are taken into consideration, the company will hold information and consultation sessions with community representatives, including the tallymen affected by the project, while the studies are under way. This will help Hydro-Québec select the route with the least impact on the concerned area.

Information

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Hydro Québec

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UPPER CANADA TRANSMISSION, INC.

**Response to Board Interrogatory 16
to all Applicants**

To the extent that your application includes a tower design not typically used in Ontario, please indicate whether the construction schedule in your application includes time for testing of new tower designs.

Response:

NextBridge's construction schedule includes time for testing of tower designs.

Testing would be required both for NextBridge's recommended (Guyed-Y) tower structure and for the lattice structure specified in NextBridge's reference case. Indeed, the precise existing Hydro One tower design is not proposed for use by any proponent, and tower testing would be required under any of the proposals before the Board.

NextBridge's structure tests will verify that the tower structures can withstand the weather load cases specified by the OEB.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 17 to all Applicants

The necessity for the requirement at paragraph 3.6.4 of the Board's Minimum Technical Requirements has been questioned. Please comment on the risk of single loop galloping and the cost of meeting the Board's requirement.

Response:

NextBridge's recommended option utilizes a Guyed-Y structure with the conductors configured in a delta arrangement. This configuration results in phase conductor offsets that typically reduce galloping issues, and satisfies the OEB requirement for single loop galloping.

The reference option that NextBridge proposes as an alternative utilizes box lattice structures as suggested by the OEB. The vertical conductor configuration of such towers requires a significant offset of the middle phase in order to meet the OEB specified galloping criteria. If the single loop galloping alternative were eliminated by the OEB, NextBridge estimates the structure material costs for this reference option could be reduced by as much as 5%. In addition, the right of way requirement could be reduced by up to a total of 4 metres for the reference option.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 18
to all Applicants

In your proposed design for the line, are there any space limitations that would restrict the ability of workers to maintain the new line?

Response:

No. In terms of the structure design, NextBridge intends to specify spacing requirements and climbing space envelopes during final development of structure layouts. These clearances will become critical design requirements for the final structure designs developed by the selected tower vendor, and will ensure that the proposed designs comply with applicable live line maintenance requirements.

In terms of right of way requirements, the specified right of way width, 50-56 m, is adequate for maintenance of the line. The right of way width provides space for access to and around the structures for live line maintenance.

See also the response to Board interrogatory 6 to all applicants.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 19
to all Applicants

Different tower structures, foundations, tower spacing, etc. were proposed in the various applications. What were the applicant's design assumptions (e.g. right-of-way spacing from Hydro One Networks Inc. ("HONI")'s assets, tower height, span length, foundation, etc.) to avoid any adverse impact to HONI's transmission system, including: (i) in the event of a catastrophic failure of the proposed new line; and (ii) access by HONI to the existing transmission line for routine maintenance and service restoration?

Response:

NextBridge has designed its project to avoid any adverse impact to HONI's transmission system. With respect to right of way spacing, NextBridge's design positions the line in the centre of a new, independent right-of-way (ROW), without overlap of the existing parallel HONI ROW. Towers proposed by NextBridge would be 43 metres high for NextBridge's recommended Guyed-Y design (50 metres for the conventional lattice towers in NextBridge's Reference Option). Foundation alternatives include concrete drilled shaft, direct embedded grillage, and grouted rock anchors, all of which have been successfully used to support lattice structures of similar design and all of which have been successfully used and are designed and tested so as to minimize chance of failure.

Transmission lines typically fail in one of two directions, transverse (perpendicular to the wires) or longitudinal (parallel to the wires).

If the NextBridge structures were to fail in the longitudinal direction, there is little chance of any impact to the adjacent HONI line.

Transverse failures are much less common than longitudinal failures. The suggested ROW widths allow for sufficient clearance for transverse structure failure without impacting adjacent transmission lines. It is extremely unlikely that a self supporting steel lattice tower will fall over and maintain its structural integrity such that a 50 meter tower will reach 50 metres from centerline during a failure. It is typical that during such a tower failure the tower will 'crumple' under the abnormal structural loading experienced. That is, a centerline to centerline separation of 50 metres for a 50 meter tower height is considered good utility practice and sufficient such that only under the most extreme of circumstances would the failed tower encroach upon adjacent HONI structures. NextBridge's recommended Guyed-Y towers, which are 43 metres high, would further reduce the risk of impacting HONI assets in the event of a transverse failure.

Where the NextBridge line crosses a HONI transmission line, the potential exists for adverse impact for loads exceeding the loads specified in the OEB's minimum design criteria. This risk would exist regardless of which applicant was chosen. NextBridge will design the crossings in compliance with CSA-C22.3 and HONI's requirements for transmission line crossings.

NextBridge would propose configuration of its line such that the new line enters each existing HONI substation in such a way as to avoid crossing the existing EWT line.

NextBridge would seek to utilize existing HONI access roads to reduce costs and environmental impacts during and after construction, both for emergency response purposes and for routine maintenance. It is understood that coordination would be required between NextBridge and HONI when sharing roads in order to avoid blocking each party's access to its facilities.

See also the response to Board interrogatory 20 to all applicants.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 20 to all Applicants

With respect to the construction, operation and maintenance of the new transmission line, what were the applicant's assumptions to avoid any adverse impact to HONI's transmission system, including: (i) in the event of a catastrophic failure of the proposed new line; and (ii) access by HONI to the existing transmission line for routine maintenance and service restoration?

Response:

NextBridge plans to construct, operate and maintain its project to avoid any adverse impact to HONI's transmission system. There is sufficient separation between the proposed NextBridge line and the existing adjacent HONI line to avoid adverse impacts.

During construction, any impact to transmission line crossings would be mitigated with good utility practices such as the use of guard structures for conductor pulls. In addition, contingency planning would be conducted with HONI.

During operation and maintenance of the line, coordination would be required between NextBridge and HONI when work on the NextBridge line is in the vicinity of HONI line crossings. For example, an insulator replacement or shield wire replacement at the crossing location.

NextBridge would seek to utilize existing HONI access roads to reduce costs and environmental impacts during and after construction. It is understood that coordination would be required between NextBridge and HONI when sharing roads in order to avoid blocking each party's access to its facilities.

See also NextBridge's response to Board interrogatory 19 to all applicants.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 21
to all Applicants

The Independent Electricity System Operator ("IESO") indicates that the double-circuit line described as the Reference Option has several benefits over the single-circuit option. These include:

- a higher thermal rating (up to about 800 MW) that can be exploited for future expansion by adding more voltage control or compensation equipment;
- a higher level of reliability because of its inherent redundancy (2 circuits to one, a lower exposure to common-mode failures, more flexibility to perform line and terminal maintenance);
- less reliance on voltage control and compensation equipment, and special protection systems;
- less electrical equipment involved and less risk of equipment failure; and
- a higher level of operating security as described in section 16 of the IESO's August 2011 Feasibility Study.

Are there any beneficial attributes of the single-circuit option, other than reduced cost? Are there other benefits of the double circuit line that are not listed above?

Response:

NextBridge agrees with the IESO's assessment, and believes that the added capacity, reliability, and O&M flexibility of the double-circuit option provide the greatest overall benefit to the project. The additional benefits of the double circuit option are:

- the ability to phase the circuits in a manner that reduces electromagnetic field levels along the corridor;

- increased flexibility in facilitating future intermediate stations to serve local load centres and/or provide transmission access for new generation (fuel-diverse, newer environmentally friendly generators);

- independent control and flexibility in redispatch during forced or scheduled outage of any of the individual circuits;

- less line losses; and

- higher load carrying capability or surge impedance loading (SIL).

NextBridge has concluded that there are no benefits from a single circuit option, compared with a double circuit option.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 22 to all Applicants

The IESO suggests that to assess whether a proposal will satisfy IESO reliability criteria at the required transfer level, some characteristics for proposals must be available. What is the a.c. resistance (at 20°C), reactance and susceptance (i.e. R, X, B) for each circuit of the Wawa to Marathon and Marathon to Lakehead sections of the new line(s)?

Response:

The following table provides impedance (resistance and reactance) and susceptance values for each of circuit configurations presented by NextBridge:

Reference Impedances for NextBridge Proposed Line Configurations							
	Length	Temp	Z+			Line Susceptance	Line Charging
Line Configuration	km	°C	Ohms			Mhos	MVAR
Reference Case: Lakehead to Marathon	232.2	20	11.307	+j	113.100	7.948E-04	45.78
Reference Case: Marathon to Wawa	168.0	20	8.180	+j	81.830	5.750E-04	33.12
Reference Case: Marathon to Wawa w/ Alts	211.0	20	10.272	+j	102.760	7.221E-04	41.59
Recommended Case: Lakehead to Marathon	232.2	20	11.201	+j	107.820	8.238E-04	47.45
Recommended Case: Marathon to Wawa	168.0	20	8.104	+j	78.007	5.960E-04	34.33
Recommended Case: Marathon to Wawa w/ Alts	211.0	20	10.176	+j	97.957	7.485E-04	43.11

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 23 to all Applicants

In the IESO Feasibility study of August 2011, the IESO indicates that it assumed a route length of approximately 400 km, and used electrical circuit parameters representative of that length of route. For transmitters proposing alternative paths that vary 40 km or more in length from the reference 400 km, please comment as to whether the change in length will materially alter the electrical parameters of the line and whether the targeted transfer capability can still be achieved.

Response:

NextBridge proposes to use the reference route which has a length of approximately 400 km, as assumed by the IESO in its feasibility study.

In its Application NextBridge considered variants to the reference route that could be used to address concerns regarding transmission line development in Pukaskwa National Park, or across First Nations lands. If all three of the variants considered were found to be appropriate during the development phase, approximately 44 km would be added to the length of the reference route.

In this event, the length of the transmission line will be just over 440 km. Given the information provided in the IESO's feasibility study and the 800 MW maximum transfer limit as reported by the IESO, it is the opinion of NextBridge's technical experts that the change in electrical parameters as a result of an increase from 400 to 444 km would not materially affect the maximum transfer limit of the line relative to the 650 MW desired transfer limit. A 444 km double circuit transmission line as described in the NextBridge Application will not materially alter the electrical parameters of the line relative to the IESO's assumed electrical circuit parameters.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 24 to all Applicants

For transmitters proposing to use 230 kV class equipment, please indicate whether the design you propose will be capable of continuous operation up to 250 kV as required by the IESO's Market Rules.

Response:

Yes. The proposed transmission line equipment has been designed to operate continuously at a line-to-line operating voltage of 250 kV.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 25
to all Applicants

Please describe any differences between the inputs that went into the Feasibility Study on record and your proposed design.

Response:

Both options proposed by NextBridge are 230kV double-circuit lines installed between the Wawa substation and the Lakehead substation, with terminations into the Marathon substation. Both options utilize 1192.5 kcmil conductors, the same conductors specified in the IESO Feasibility Study. However, since NextBridge's Recommended Plan, which uses guyed structures is different than the Reference Plan, which uses steel lattice structures, there are minor differences in impedance (see R, X and B as identified in the answer to response to Board interrogatory 22 to all applicants). It is the opinion of NextBridge's technical experts that these minor differences will not materially alter the electrical parameters of the line relative to the IESO's assumed electrical circuit parameters.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 26 to all Applicants

Please complete the following three tables to enhance cost comparability between applications. Applicants should provide the cost estimates based on their preferred option for the line. Where the preferred option is not the reference option, the tables should also be provided for the reference option.
In completing the tables, please assume the following:

- All figures should be stated in 2012 dollars, without escalation in labour, materials or other costs.
- The development phase ends with the filing of a leave to construct application with the Board.
- Taxes and duties should be excluded.

Development Activity	**Estimated Cost**	**Reference in filed application**
Engineering, design, and procurement activity		
Materials and equipment		
Permitting and licensing		
Environmental and regulatory approvals		
Land rights (acquisition or options), including consultation and negotiation with landowners		
First Nation and Métis participation (direct and indirect costs, including impact mitigation if applicable)		
First Nation and Métis consultation		
Other consultation (community, stakeholder)		

Development Activity	**Estimated Cost**	**Reference in filed application**
IDC or AFUDC (if included in estimates)		
Contingency		
Other (explain in detail)		
Total		

Construction Activity	**Estimated Cost**	**Reference in filed application**
Engineering, design, and procurement activity		
Materials and equipment		
Permitting and licensing		
Environmental and regulatory approvals		
Land rights (acquisition or options), including consultation and negotiation with landowners		
First Nation and Métis participation (direct and indirect costs, including impact mitigation if applicable)		
First Nation and Métis consultation		
Other consultation (community, stakeholder)		
Site clearing and preparation		
Construction		
Site remediation		
IDC or AFUDC (if included in estimates)		

Construction Activity	**Estimated Cost**	**Reference in filed application**
Contingency		
Other (explain in detail) e.g. CWIP		
Total		

Operations and Maintenance Activity	**Estimated Cost**	**Reference in filed application**
Major activities (please list, but cost estimate may be bundled)		
Administration and general costs related to O&M		
Regulatory costs		
Contingency		

Response:

See Attachment 1.

Development Activity	Recommended Plan Estimated Cost	Reference Plan Estimated Cost	Reference in filed application
Engineering, Design, and Procurement Activity	10,553,085	10,553,085	Section 8.2 - Figure 21 - *Engineering & Design*
Materials and Equipment	-	-	Section 8.2 - Figure 21 - *Materials & Procurement*
Permitting and Licensing	46,667	46,667	Section 8.2 - Figure 21 - *Permitting, Licensing, Environmental*
Environmental and Regulatory Approvals	3,593,500	3,593,500	Section 8.2 - Figure 21 - *Permitting, Licensing, Environmental*
Land Rights (acquisitions or options), including consultation and negotiation with landowners	1,990,805	1,990,805	Section 8.2 - Figure 21 - *Land Acquisition & Aboriginal Affairs* *
First Nation and Metis participation (direct and indirect costs, including impact mitigation if applicable)	-	-	Not Included *
First Nation and Metis consultation	1,723,375	1,723,375	Section 8.2 - Figure 21 - *Land Acquisition & Aboriginal Affairs*
Other Consultation (community, stakeholder)	496,240	496,240	Section 8.2 - Figure 21 - *Land Acquisition & Aboriginal Affairs*
IDC or AFUDC	-	-	Not Included
Contingency	1,319,136	1,319,136	Section 8.2 - Figure 21 - *Engineering & Design*
Other (explain in detail)			
Regulatory (Legal Support, Rate Case Filing, LTC Filing)	985,240	985,240	Section 8.2 - Figure 21 - *Other Significant Expenditures*
Interconnection Studies	179,210	179,210	Section 8.2 - Figure 21 - *Other Significant Expenditures*
Project Management	1,299,764	1,299,764	Section 8.2 - Figure 21 - *Other Significant Expenditures*
TOTAL (2012 Dollars)	**22,187,022**	**22,187,022**	**Total Removing Escalation**
Escalation (To Bring back to 2012 Dollars)	211,062	211,062	Section 8.2 - Figure 21 - *Engineering & Design*
TOTAL (Including Escalation)	**22,398,084**	**22,398,084**	**Total Including Escalation - Matches Application**

Construction Activity	Recommended Plan Estimated Cost	Reference Plan Estimated Cost	Reference in filed application
Engineering, Design, and Procurement Activity	13,235,907	13,243,117	Section 8.7 - Figure 23 - *Engineering & Design*
Materials and Equipment	52,168,975	69,423,822	Section 8.7 - Figure 23 - *Materials & Procurement*
Permitting and Licensing	193,333	193,333	Section 8.7 - Figure 23 - *Permitting, Licensing, Environmental*
Environmental and Regulatory Approvals	3,027,770	3,027,770	Section 8.7 - Figure 23 - *Permitting, Licensing, Environmental*
Land Rights (acquisitions or options), including consultation and negotiation with landowners	17,135,214	17,135,214	Section 8.7 - Figure 23 - *Land Acquisition and Aboriginal Affairs* *
First Nation and Metis participation (direct and indirect costs, including impact mitigation if applicable)	-	-	Not Included *
First Nation and Metis consultation	5,526,345	5,526,345	Section 8.7 - Figure 23 - *Land Acquisition and Aboriginal Affairs*
Other Consultation (community, stakeholder)	841,040	841,040	Section 8.7 - Figure 23 - *Land Acquisition and Aboriginal Affairs*
Site clearing and preparation (including Roads)	52,293,201	50,610,924	Section 8.7 - Figure 23 - *Construction*
Construction	180,234,437	193,123,999	Section 8.7 - Figure 23 - *Construction*
Site remediation (Neutral Footprint)	10,307,996	9,690,100	Section 8.7 - Figure 23 - *Permitting, Licensing, Environmental* Section 8.7 - Figure 23 - *Construction*
IDC or AFUDC	-	-	Not Included
Contingency	35,708,360	38,990,910	Section 8.7 - Figure 23 - *Construction* Section 8.7 - Figure 23 - *Materials & Procurement* Section 8.7 - Figure 23 - *Engineering & Design*
Other (explain in detail)			
Regulatory (Legal Support, Rate Case Filing, LTC Filing)	3,642,806	3,642,806	Section 8.7 - Figure 23 - *Other Significant Expenditures*
Project Management	3,197,888	3,197,888	Section 8.7 - Figure 23 - *Other Significant Expenditures*
TOTAL (2012 Dollars)	**377,513,272**	**408,647,268**	**Total Removing Escalation**
Escalation (To Bring back to 2012 Dollars)	19,148,348	20,918,600	Section 8.7 - Figure 23 - *Construction* Section 8.7 - Figure 23 - *Materials & Procurement* Section 8.7 - Figure 23 - *Engineering & Design*
TOTAL (Including Escalation)	**396,661,620**	**429,565,868**	**Total Including Escalation - Matches Application**

Operations and Maintenance Activity	Recommended Plan Estimated Cost	Reference Plan Estimated Cost	Reference in filed application
Major activities (please list but cost estimate may be bundled)			
Inspection (air & ground), Patrols, Vegetation & Right of Way Management	740,000	740,000	Section 8.12 - Figure 25 - *Operations and Maintenance*
O&M Staffing, Field Office, Technical Support services	511,000	511,000	Section 8.12 - Figure 25 - *Operations and Maintenance*
Administration and general costs related to O&M	1,346,000	1,346,000	Section 8.12 - Figure 25 - *Administration and General*
Regulatory costs	1,850,000	1,850,000	Section 8.12 - Figure 25 - *Regulatory Compliance*
Contingency	-	-	Not Included
TOTAL (2012 Dollars)	**4,447,000**	**4,447,000**	**Matches Application**

* As stated in the UCT Application, an estimate for First Nation and Métis land acquisition is not included as this will be determined at a later date after engagement and consultation have advanced.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 27 to all Applicants

a) Please confirm that while costs may be reaggregated into the specified categories, the amounts in the tables are consistent with the overall estimates filed in your application.

b) Please reconcile each of the development, construction and operation phase totals produced in the tables with the total costs for each of these phases put forward in your application. The reconciliation should describe and quantify each reconciling element.

Response:

a) NextBridge confirms that the overall amounts in the tables are consistent with the overall estimates filed in its application.

b) Reconciliation entries for escalation have been added to the chart in the response to Board interrogatory 26 to all applicants.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 28 to all Applicants

For each phase, please describe how the contingency amounts were determined.

Response:

As discussed in Section 8.3 of the NextBridge application, the Development Phase budget was determined using a 'bottom-up' methodology, with each activity being assessed at its expected cost without a specific amount set aside for "contingency", with the exception of Engineering and Design. Each technical team identified in response to Board interrogatory 1 to all applicants, as identified in Section 4.1 of the NextBridge application, was responsible for developing a portion of the overall budget. As can be seen in the table provided in response to Board interrogatory 26 to all applicants, incremental contingency was included as part of the Engineering and Design effort during the Development Phase. We believe the application of incremental contingency for Engineering and Design is appropriate due to that category of costs' impact to the overall budget. The contingency has been derived from proprietary percentages, developed through our extensive history of successful project execution, and applied to the component parts.

For the Construction Phase, the cost estimates contained in NextBridge's Application were led by NextEra in consultation with our external engineering and construction advisors. As can be seen in the table provided in response to Board interrogatory 26 to all applicants, contingency has been specifically assessed as part of the construction, materials and procurement, and engineering and design efforts during the Construction Phase. The size of the contingency reflects the relative size of the cost categories to the overall budget. The contingency has been derived from proprietary percentages, developed through our extensive history of successful project execution, and applied to the component parts.

While NextBridge's formulas for calculating contingencies are proprietary, we believe that the historical project actual vs. budget information provided in response to Board interrogatory 32 to all applicants validates NextBridge's ability to produce accurate financial forecasts for its projects.

As with the Development Phase, the Operation and Maintenance Phase budget was determined using a 'bottom-up' methodology. This takes into account detailed variability for different maintenance tasks that are required over the life of the project. Due to the rigor of the effort and the preliminary nature of the estimate, we do not believe it appropriate to add an additional stand-alone contingency value to this Phase.

UPPER CANADA TRANSMISSION, INC.

**Response to Board Interrogatory 29
to all Applicants**

With respect to operation, maintenance and administration costs, please indicate whether the applicant's stated OM&A costs are estimated on a standalone basis (i.e. the full OM&A costs of the line) or on a net basis (i.e. excluding costs incurred by affiliates or other regulated utilities providing services to the applicant). If on a net basis, please provide in detail the applicant's estimated OM&A costs on a standalone basis.

Response:

OM&A costs are estimated on a standalone basis.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 30 to all Applicants

With respect to the provision of services by HONI:

a) What specific services were assumed in the application?

b) What were the assumed associated costs?

c) In the absence of any input from HONI, on what basis were these assumptions made?

d) What is the impact on the application if the assumed services are not provided by HONI as envisioned by the applicant?

Response:

a) With respect to provision of services by HONI, NextBridge assumes per the filing requirements and project descriptions that all operations and maintenance activities related to existing substation facilities are to be performed by the owner of these facilities, which is HONI. NextBridge has not assumed it receives any services from HONI with respect to the new facilities owned by NextBridge.

However, NextBridge also assumes it will coordinate with HONI to establish a data link from HONI control centers to the NextBridge monitoring operations centre for situational awareness and required 24x7 cooperation and communications with HONI system operators on any issues affecting the transmission line assets.

b) The assumed costs associated with the data link are minor in nature; estimated at $50,000-100,000 for initial hardware and circuit set up and an on-going communications systems and circuit cost of $30,000-40,000 per year. Detailed estimates will be established as part of the overall development and engineering phase of the project. These costs are included in NextBridge's project cost estimates.

c) These assumptions were made without any initial input from HONI, however, they are based on broad experience in setting up communications links throughout North America on various transmission and generation projects. A specific platform and format will be developed during the detailed development and engineering phase of the project in coordination with HONI. In the interim, the assumed minor associated costs are based on the experience of NextEra affiliates NextEra Energy Resources, NextEra Energy Transmission, Lone Star Transmission and Florida Power & Light, which affiliates operate numerous data links between their assets and the control centres of interconnected transmission parties as well as with reliability coordinators in the Florida Reliability Coordinating Council and Electricity Reliability Council of Texas regions.

d) The communications service described above is a standard practice for data exchange among and between utilities and transmission companies operating under the North American Electric Reliability Corporation (NERC) processes. As such, NextBridge expects to successfully coordinate the establishment of this data link with HONI.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 31 to all Applicants

With respect to the use, modification or expansion of HONI's stations:

a) What specific uses, modifications or expansions were assumed in the application?

b) What were the assumed associated costs?

c) In the absence of any input from HONI, on what basis were these assumptions made?

d) What is the impact on the application if the assumed uses, modifications or expansions do not proceed as envisioned by the applicant?

Response:

a) No uses, modifications or expansions of HONI's stations were assumed, other than those indicated by Board Staff in the introductory meetings held at the OEB. These assumptions involve HONI's expansion of its substations to accommodate the entrance and/or exit of an additional two circuits at each of the identified substations.

b) NextBridge did not include any associated costs in its estimate, as these costs are common to all proponents, unless a proponent submitted an alternative proposal.

c) Not applicable.

d) NextBridge will be unable to energize the new transmission line until the substations expansion is complete. This is a common risk for all proponents.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 32 to all Applicants

Please complete the following tables, detailing all transmission projects greater than 100 km in length, undertaken by the applicant, its partners, shareholders, affiliates, or any other entities which the applicant is relying on for the purposes of its application, in the past 10 years in all jurisdictions. Please provide the reasons for the budget and schedule variances for each project.

a) Budget Variance Table

Name of project	Details of project	Budgeted cost	Stage of process at which budget created	Actual cost	Variance	Reason for variance

b) Schedule Variance Table

Name of project	Details of project	Estimated development and construction time	Stage of process at which time estimate made	Actual development and construction time	Variance	Reason for variance

---

Response:

For ease of reading, NextBridge has isolated the project descriptions outside the table.

Lone Star Transmission, LLC (LST)

- Rate regulated transmission operator in Texas.
- 512 km, primarily double circuit 345 kV.
- Five high voltage transmission substations, including series compensation and reactive resources.
- Begins in the Abilene area of Texas to just south of the Dallas metropolitan area.
- Included approximately 1000 tracts of land and 700 landowners.
- Terrain features include a mix of high sandy plains, prairies, savannah, woodlands, limestone surface formations, as well as rocky terrain crossed by narrow streams, occasional drop offs and rolling terrain with clay soils.

Texas Clean Energy Express (TCEE)

- Private generator tie line that connects the Horse Hollow area wind facilities near Abilene, Texas to the LCRA Kendall Substation, southwest of Austin, Texas.
- 344 km, single circuit 345kV and associated 138 kV radial feeders.
- Two 345 kV substations and six 138 kV collection substations including series compensation.
- 270 landowners, 504 crossing agreements, all negotiated without access to the right of expropriation.
- Begins in the Abilene area of Texas with rolling countryside, and transitions into “Hill Country” of central Texas marked by numerous canyons, rocky terrain with occasional steep drop offs and numerous long-span peak to peak crossings of up to 700 feet; the route is heavily wooded with only small portions containing significant areas of population.

Blythe Energy, LLC (BE)

- Private generator tie line that connects the 520 MW Blythe Energy plant to the California ISO Julian Hinds substation.
- 108 km, single circuit 230 kV.

- Two-thirds of the land is managed by the U.S. Department of the Interior, Bureau of Land Management, as well as approximately an additional 50 private landowners.

- Terrain includes agricultural lands in the Palo Verde Valley, California, crossing desert lands with scrub, trees and shrubs, sand dunes and blowing sand playas; there is steeper topography near Desert Center, CA, including unvegetated rock outcrops and some rocky shrub lands.

Peetz-Logan Intertie (PLI)

- Private generator tie line located between Peetz and Fort Morgan, Colorado.

- 125 km, single circuit 230 kV.

- Over 50 separate landowners.

- The majority of the route is rolling grassland plains typical of Northeastern Colorado.

Montana-Alberta Tie Line (MATL)

- Contracted merchant transmission line from Great Falls, Montana to Lethbridge, Alberta

- 330 km, 230 kV single circuit

- The line is situated on a combination of privately owned agricultural crop land; Crown lands and State of Montana grasslands with low to very low population densities.

a) Budget Variance Table

Name of project	Budgeted cost	Stage of process at which budget created	Actual cost	Variance	Reason for variance
LST	$794.1 MM	Public Utility Commission of Texas – Certificate of Convenience and Necessity Filing - April 2010	Forecast cost to completion is $731.6 MM. Commercial operation commenced March, 2013	($62.5 MM)	Reductions in AFUDC due to lower capital expenditure, as a result of favourable pricing of EPC services due to negotiations with vendors.
TCEE	$238 MM	NextEra OpComm [1] – June 2008	$267.4 MM	$29.4 MM	Increase in line length from 315 to 344 km, due to inability to expropriate. Addition of capacitor banks, extensive rock excavation.
BE	$95 MM	NextEra OpComm [1] – January 2009	$80 MM	($15 MM)	Favourable pricing of EPC services. Decision to lease versus building substation.
PLI	$34.1 MM	NextEra Board Meeting - May 2006	$36.1 MM	$2.0 MM	Line length increase from 107 to 125 km, offset by per km construction costs decreased.
MATL	$139 MM	The budget was created when the asset was acquired in Q3 2011. At the time construction had been halted by previous owners.	Ongoing with costs not finalized.	Estimated at $25 MM	Increased contractor and legal costs due to regulatory delay and remediation of construction issues (legacy issues associated with previous project owner).

b) Schedule Variance Table

Name of project	Estimated development and construction time	Stage of process at which time estimate made	Actual development and construction time	Variance	Reason for variance
LST	4 years, 2 months[2]	Public Utility Commission of Texas – Certificate of Convenience and Necessity Filing 4/2010	4 years, 2 months	None	Not applicable.
TCEE	16 months	OpComm[1] – June 2008	15 months	(1 month)	Expediting and paralleling of development, design and construction activities.
BE	18 months	OpComm [1] – January 2009	16.5 months	(6 weeks)	Construction expediting.
PLI	17 months	NextEra Board Meeting - May 2006	16 months	(1 month)	Construction expediting.
MATL	Approximately 1 year from the date of acquisition, with expected completion by end of September 2012.	The schedule was created when the asset was acquired in Q3 2011.	Ongoing with expected completion by end of June 2013.	Estimated at 9 months	Regulatory delay.

1 OpComm (Operating Committee) is an internal NextEra vetting and approval process which includes a presentation of project budget, schedule, risks and benefits. OpComm approves the budget for a given project.

[2] Based on 2009-01-29 Texas Public Utility Commission award of CREZ project through a 2013-03-31 construction completion.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 1 to UCT

Please provide full and complete organization particulars of NextBridge Infrastructure LP, including a listing of all limited partners and their respective interests in NextBridge Infrastructure LP.

Response:

NextBridge Infrastructure LP ("NextBridge") is a limited partnership formed under the laws of Ontario. An organizational chart graphically depicting the structure is attached.

NextBridge has one general partner and three limited partners.

General Partner:

NextBridge's sole general partner is Upper Canada Transmission, Inc., a corporation formed under the laws of New Brunswick. Upper Canada Transmission, Inc. holds a 0.01% distribution interest in NextBridge (up to a maximum of $1,000). Upper Canada Transmission, Inc., has the following three shareholders:

a) NextEra Energy UCT Holding, Inc., a corporation formed under the laws of New Brunswick, owns 100 common shares constituting 50% of the issued and outstanding shares of Upper Canada Transmission, Inc.;

   (i) NextEra Energy UCT Holding, Inc. is wholly-owned by NextEra Energy Canada, ULC, an unlimited liability company formed under the laws of Alberta;

b) Enbridge Transmission Holdings Inc., a corporation formed under the laws of Canada, owns 50 common shares constituting 25% of the issued and outstanding shares of Upper Canada Transmission, Inc.;

   (i) Enbridge Transmission Holdings Inc. is wholly-owned by Enbridge Inc., a corporation formed under the laws of Alberta;

c) Borealis EWT Inc., a corporation formed under the laws of Ontario, owns 50 common shares constituting 25% of the issued and outstanding shares of Upper Canada Transmission, Inc.;

   (i) Borealis EWT Inc. is a subsidiary of OMERS Administration Corporation, a statutory corporation without share capital established to administer the pension plans for employees of municipal governments, school boards, libraries, police and fire departments, children's aid societies, and other local agencies across Ontario (collectively, the "Pension Plans") pursuant to the *Ontario Municipal Employees Retirement System Act*, 2006, S.O. 2006, c. 2 ("OMERS Act").

Limited Partners:

NextBridge has three limited partners.

a) NextEra Energy NextBridge Holding, Inc., a corporation formed under the laws of New Brunswick, will, upon the initial capitalization of NextBridge, hold 50% of the limited partnership units of NextBridge;

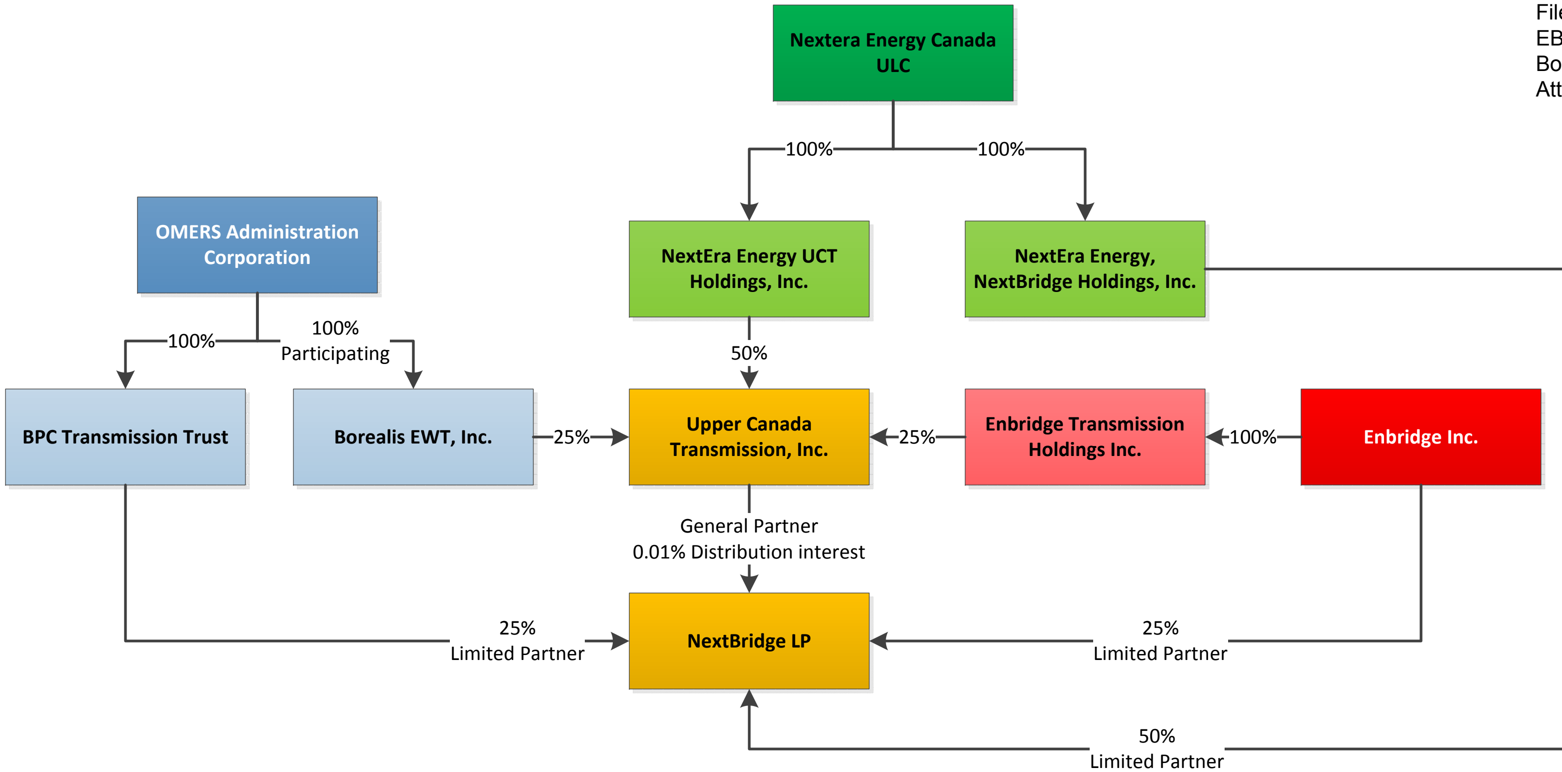
   (i) NextEra Energy NextBridge Holding, Inc., is wholly owned by NextEra Energy Canada, ULC, an unlimited liability company formed under the laws of Alberta;

b) Enbridge Inc., a corporation formed under the laws of Alberta, will, upon the initial capitalization of NextBridge, hold 25% of the limited partnership units of NextBridge;

c) BPC Transmission Trust, a trust formed under the laws of Ontario, will, upon the initial capitalization of NextBridge, hold 25% of the limited partnership units of NextBridge;

   (i) BPC Transmission Trust is a subsidiary of OMERS Administration Corporation, a statutory corporation without share capital established to administer the pension plans for employees of municipal governments, school boards, libraries, police and fire departments, children's aid societies, and other local agencies across Ontario (collectively, the "Pension Plans") pursuant to the *Ontario Municipal Employees Retirement System Act*, 2006, S.O. 2006, c. 2 ("OMERS Act").

Filed: 2013-03-28
EB-2011-0140
Board #1 (UCT)
Attachment 1



UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 2 to UCT

Please provide copies of the most recent credit rating reports for each of:

- NextEra Energy Capital Holdings
- Enbridge Inc.
- Borealis Infrastructure Management

Response:

S&P and Fitch do not issue a separate report for NextEra Energy Capital Holdings, but include it as part of NextEra Energy, Inc. Listed below are the attached credit reports and if applicable, the page reference to the NEECH credit ratings.

- Fitch - NextEra Energy, Inc. (NEECH ratings on page 1) (Attachment 1)
- Standard and Poor's - NextEra Energy, Inc. (NEECH ratings on page 9) (Attachment 2)
- Moody's - NextEra Energy, Inc. (Attachment 3)
- Moody's - NextEra Energy Capital Holdings, Inc. (Attachment 4)
- Standard and Poor's – Enbridge Inc. (Attachment 5)
- DBRS – Enbridge Inc. (Attachment 6)
- Moody's – Enbridge Inc. (Attachment 7)
- Standard and Poor's – OMERS Administration Corporation (Attachment 8)

NextEra Energy, Inc.

And NextEra Capital Holdings, Inc.

Full Rating Report

Ratings

NextEra Energy, Inc.

Long-Term IDR	A–

NextEra Energy Capital Holdings, Inc.

Long-Term IDR	A–
Senior Unsecured	A–
Junior Unsubordinated	BBB
Commercial Paper	F1

IDR – Issuer default rating.

Rating Outlook

Long-Term IDR	Stable

Financial Data

NextEra Energy, Inc.

($ Mil.)	LTM 6/30/12	YE 12/31/11
Revenue	15,204	15,260
Operating EBITDA	5,311	4,915
Op. EBITDA/ Revenues (%)	56	55
CFFO	3,956	4,018
FCF	(4,803)	(3,530)
FFO/Interest Expense (x)	4.69	4.72
Total Debt	22,837	21,303
Total Debt/Op. EBITDA (x)	4.30	4.33
FFO/Debt (%)	19.01	19.83

Related Research

Florida Power & Light Co. (October 2012)

U.S. Utilities: Insatiable Thirst for Financing (September 2012)

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Key Rating Drivers

Growing Regulated Mix: NextEra Energy, Inc.'s (NEE) ratings reflect a shifting business mix through 2015 towards regulated and highly contracted cash flows. This is being driven by significant rate base growth at its utility subsidiary, Florida Power & Light (FPL), completion of the regulated Lone Star transmission line in 2013, weak wholesale prices that reduces the contribution of noncontracted generation assets, and rising contribution from solar and Canadian wind investments. Fitch Ratings forecasts that regulated utility businesses will contribute approximately 55% of NEE's EBITDA for the next several years, and contractual sources another 25%–30%.

High Capex: Consolidated capex is expected to spike close to $8.6 billion in 2012, primarily driven by rate base growth at FPL and approximately 1,500 MW of U.S. wind investments, putting pressure on credit metrics. Fitch expects 2013 capex to decline significantly from the current year's peak and progressively decline thereafter, leading NEE to turn FCF positive in 2014. Fitch's capex estimates reflect only the announced and committed projects.

Improving Credit Metrics from 2013: Fitch anticipates NEE's credit measures to improve from 2013, led by a base rate increase at FPL and contributions from new renewable investments at NextEra Capital Holdings, Inc. (Capital Holdings). Fitch expects NEE's EBITDA coverage to be 4.7x–5.0x and adjusted debt to EBITDA (reflecting recourse debt only) to be 3.5x–4.0x by 2015. These metrics are considerably weaker than peer 'A–' holding companies, since NEE's EBITDA does not capture the tax attributes of the renewable projects that are funded by recourse debt. Fitch forecasts NEE's FFO to adjusted debt to be 21%–23% and FFO to interest to approximate 5.1x by 2015.

Debt Leverage and Mitigants: NEE's credit metrics, as reported, show more leverage than 'A–' peers. However, Fitch considers several mitigating factors. These include longer term off-take contracts at competitive power subsidiaries relative to peers (more than 90% hedged over 2012–2013), a high concentration of non-utility generation in renewable and nuclear resources with favorable environmental characteristics, and a high proportion of consolidated debt in the form of project finance loans that have limited or no corporate recourse. Fitch accords off-credit treatment to NEE's limited recourse project debt, reflecting Fitch's assumption that the company will walk away from these projects in the event of financial deterioration.

What Could Trigger a Rating Action

Deterioration in Florida Regulation: Any change in current regulatory policies or adverse outcome in the pending rate case at FPL would adversely affect NEE's ratings.

Increase in Business Risk Profile: A change in strategy to invest in more speculative assets, noncontracted renewable assets, or a lower proportion of cash flow under long-term contracts would increase business risk and could result in lower ratings for NEE. The high level of capital expenditures at Capital Holdings creates completion and funding risks.

Aggressive Financial Strategy: Any deterioration in credit measures that result from higher leverage or outsized return of capital to shareholders could lead to negative rating actions.

Financial Overview

Liquidity and Debt Structure

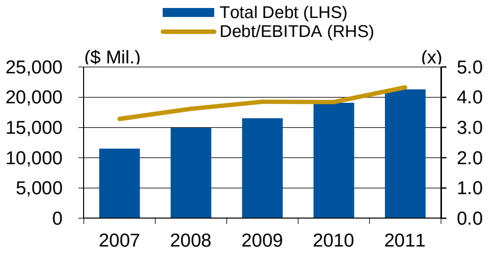
Debt Maturities[a]

($ Mil., As of June 30, 2012)

2012	205
2013	2,160
2014	1,171
2015	1,506
After 2015	17,993
Cash and Cash Equivalents	295
Undrawn Committed Facilities	4,951

[a]Excludes storm securitization bonds.
Source: Company data, Fitch.

Total Debt and Leverage



Source: Company data, Fitch.

NEE's total net available liquidity as of June 30, 2012 was $5.2 billion, of which FPL's portion was $2.7 billion. Approximately $1.1 billion of FPL's and $1.5 billion of Capital Holdings' credit facilities expire in 2013, while the remaining facilities expire in 2017. NEE has strong access to capital markets, the commercial paper market, and to banks for both corporate credit and project finance.

Consolidated debt at NEE has doubled over the last five years to finance a rapid growth in renewable investments at NextEra Energy Resources (Energy Resources), a wholly owned subsidiary of Capital Holdings, and also to fund rate base growth at FPL. Unlike most of its peers, Capital Holdings and its subsidiaries use a variety of instruments for debt financing, such as corporate debentures, project debt, hybrids, and sale of differential membership interests in renewable projects.

Corporate debt at Capital Holdings is subordinate to the project-level debt at Energy Resources. NEE's consolidated debt as of June 30, 2012 comprised $6.0 billion of limited recourse project debt, which Fitch treats as off-credit in its credit analysis. This reflects Fitch's assumption that management will walk away from projects funded with such debt if project economics worsen. A quick payback of NEE's equity investment on projects funded with project debt or tax equity (typically two to three years) supports Fitch's assumption.

Cash Flow Analysis

NEE's strategy focuses on growth through ongoing capital investment, like many utility and competitive power entities. Thus, NEE has negative FCF after dividends and capex. Consolidated capex averages approximately $5.0 billion–$6.0 billion annually, with high rates of investment at both FPL and Capital Holdings.

Related Criteria

Corporate Rating Methodology (August 2012)

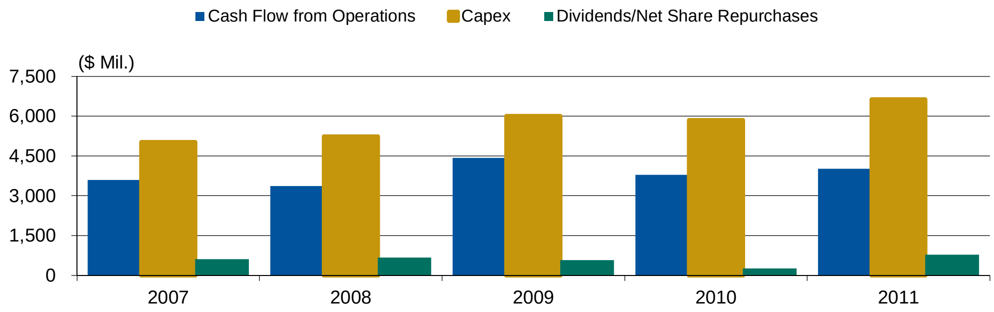
Parent and Subsidiary Rating Linkage (August 2012)

Recovery Ratings and Notching Criteria for Utilities (May 2012)

Treatment and Notching of Hybrids in Nonfinancial Corporate and REIT Credit Analysis (December 2011)

Fitch forecasts NEE's cash flow from operations to exceed capex after 2012 with the completion of the significant U.S. wind build at Energy Resources. Fitch expects NEE to turn FCF positive on a consolidated basis in 2014 as the Cape Canaveral and Riviera Beach modernization projects at FPL are completed in 2013 and 2014, respectively. The capex associated with Canadian wind, Solar PV projects and the Port Everglades modernization project extends up to 2016, but is manageable given the robust cash flow from operations. However, it is quite likely that management will invest in additional renewable projects; a key driver for which will be the extension of production tax credits (PTCs) for new U.S. wind investments.

CFO and Cash Use



Source: Company data, Fitch.

Peer and Sector Analysis

Peer Group Analysis

	NextEra Energy, Inc.	MidAmerican Energy Company	Dominion Resources, Inc.	Sempra Energy
LTM as of	6/30/12	6/30/12	6/30/12	6/30/12
Long-Term IDR	A–	A–	BBB+	BBB+
Outlook	Stable	Stable	Stable	Stable
Financial Statistics ($ Mil.)				
Revenue	15,204	3,301	13,526	9,652
YoY Revenue Growth (%)	1	(9)	(10)	4
EBITDA	5,311	788	3,833	2,696
EBITDA Margin (%)	34.93	23.87	28.34	27.93
FCF	(4,803)	627	(1,153)	(2,351)
Total Adjusted Debt	22,837	3,147	19,834	11,775
Cash and Cash Equivalents	295	271	162	221
Funds Flow from Operations	4,341	1,063	3,262	2,090
Capex	(7,798)	(605)	(3,981)	(3,695)
Net Equity Proceeds	459	0	145	37
Credit Metrics (x)				
EBITDA/Gross Interest Coverage	4.52	4.75	4.03	4.86
Debt/FFO	5.26	2.96	6.08	5.63
Debt/EBITDA	4.30	3.99	5.17	4.37
FFO Interest Coverage	4.69	7.40	4.43	4.77
Capex/Depreciation (%)	546.08	162.20	352.93	361.55

IDR – Issuer default rating. YoY – Year over year.
Source: Company data, Fitch.

Peer Group

Issuer	Country
A–	
MidAmerican Energy Company	U.S.
BBB+	
Dominion Resources, Inc.	U.S.
Sempra Energy	U.S.

Issuer Rating History

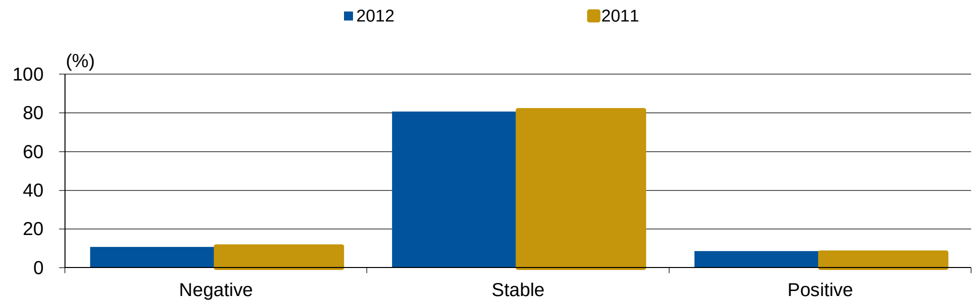
Date	LT IDR	Outlook/ Watch
April 27, 2012	A–	Stable
May 2, 2011	A–	Stable
April 30, 2010	A–	Negative
Jan. 12, 2010	A	RWN
Oct. 29, 2009	A	Stable
Dec. 14, 2007	A	Stable
Dec. 20, 2006	A	Stable

RWN – Ratings Watch Negative.

As-reported debt and leverage metrics for NEE show higher leverage relative to peers. However, Fitch considers several mitigating factors when analyzing NEE's credit metrics, such as:

- NEE's EBITDA does not capture the tax attributes of the renewable projects that are funded by recourse debt;
- A high proportion of consolidated debt is in the form of project finance loans that have limited or no corporate recourse;
- Longer term off-take contracts at a competitive power subsidiary relative to peers (more than 90% hedged over 2012–2013); and
- A high concentration of non-utility generation in renewable and nuclear resources with favorable environmental characteristics.

Sector Outlook Distribution



Source: Fitch.

Key Rating Issues

Shifting Business Mix

Fitch expects NEE's cash flows from stable utility-type sources to grow over 2012–2015. At FPL, recovering retail sales and future rate cases to incorporate new rate base investments will produce revenue uplift. At Capital Holdings, completion of new Texas electric transmission assets will result in predictable tariff revenues. Fitch forecasts that regulated businesses will contribute more than 55% of NEE's EBITDA for the next several years. Within the nonregulated operations of Energy Resources, the contribution of long-term contracted generation assets will increase. Fitch expects contractual sources to drive another 25%–30% of NEE's consolidated EBITDA over the next few years. Management recently revised its dividend policy and is targeting a 55% payout ratio in 2014, in conjunction with the shifting business mix.

Renewable Focus, Highly Contracted Non-Utility Operations

NEE continues to focus on concentrating its power portfolio in noncarbon emitting resources (nuclear, wind, hydroelectric, and solar) and low-CO2 emitting resources (natural gas). Fitch expects NEE's relatively clean generation fleet to benefit from stricter environmental regulations imposed by the Environmental Protection Agency (EPA) and from the continued support to renewable policies at the state level. Energy Resources' assets are largely contracted in line with management's philosophy of targeting stable cash flows and mitigating commodity exposure. Non-utility gross margin is more than 90% hedged for 2012–2014 based on latest company disclosures. The company has modest exposure to energy retailing in the ERCOT market, and small exposure to wholesale market and spot energy transactions.

Capex Levels Taper Off in Fitch's Forecasts

Fitch expects consolidated capex to spike close to $8.6 billion in 2012 and then significantly decline 2013 onwards. Fitch's financial forecasts do not incorporate any incremental capex beyond the announced projects that underpin management's targeted earnings growth rate of 5%–7% over 2011–2014. A significant driver of future capex growth at Energy Resources remains the extension of PTCs for U.S. wind generation, which, absent congressional action, will expire at the end of 2012. Energy Resources continues to pursue additional renewable opportunities in solar and Canadian wind, as well as acquisition opportunities in U.S. wind, which could increase the capex beyond what is currently incorporated in Fitch's forecasts. Fitch expects the operating cash flow at Capital Holdings to significantly improve from 2014 onwards as tax payments from the parent resume, assuming no extension of bonus depreciation benefits. This should accord higher financial flexibility to Capital Holdings to fund future investments.

Regulatory Update

Utility management is focused on achieving a constructive outcome for its pending rate increase request. FPL has filed a $517 million rate increase request for new rates to be effective January 2013, and an additional base rate increase of $174 million commencing with the completion of the modernization at Cape Canaveral (expected June 2013). FPL has requested a return on equity (ROE) of 11.25%, with a 0.25% adder if FPL maintains the lowest typical residential bill in the state. FPL has also entered into a partial settlement agreement with four intervenors. The Florida Public Service Commission (FPSC) has heard oral arguments regarding the proposed settlement, and has asked for additional, expedited hearings before issuing an order.

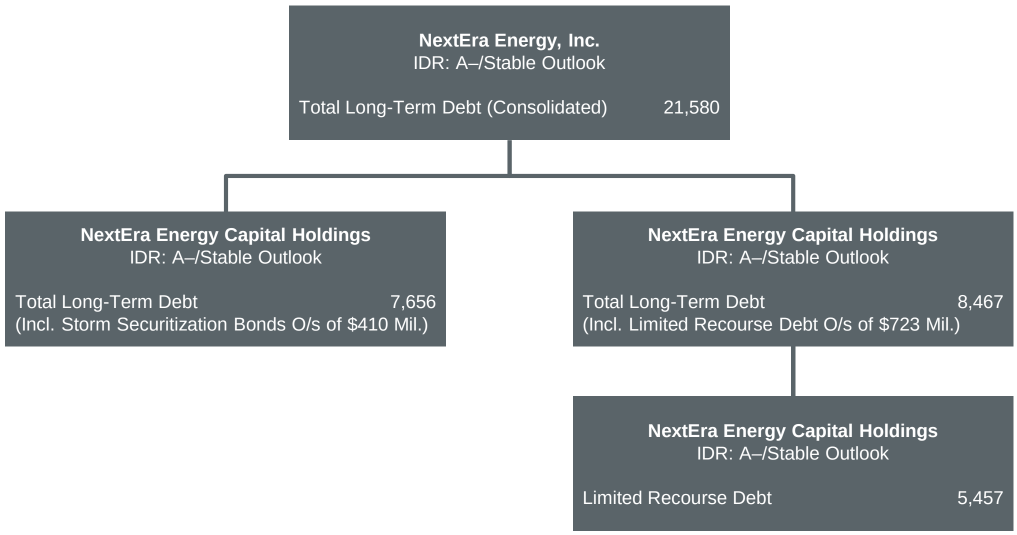
Reliance on Tax Incentives

NEE's cash flow has been buoyed by significant tax incentives such as production and investment tax credits, and accelerated depreciation and bonus depreciation benefits. NEE has accumulated tax incentives that Fitch assumes the company can continue to monetize against taxable income or via tax-oriented partnerships. Fitch forecasts NEE to start paying cash taxes beginning 2014, assuming no extension of bonus depreciation benefits, no incremental tax subsidies for U.S. wind projects, and no incremental renewable investments beyond the announced projects. The scale of additional investments beyond 2012, source of funding for the incremental capex, and capital allocation of positive FCF beyond 2014 will be key drivers for NEE's future credit measures.

Organizational Structure

There is no debt at NEE. Capital Holdings is a financing vehicle that issues corporate recourse debt on behalf of its parent, NEE, to fund investments in the non-utility operating subsidiaries. All Capital Holdings' debt obligations are guaranteed by NEE, which is the credit basis for Capital Holdings' issuer default rating (IDR).

Organizational and Debt Structure
($ Mil., As of June 30, 2012)



IDR – Issuer default rating. O/s – Outstanding. NR – Not rated.
Source: Company data, Fitch.

Definitions

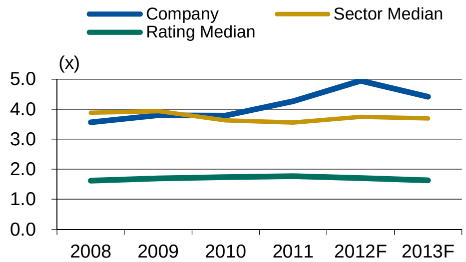
- Leverage: Gross debt plus lease adjustment minus equity credit for hybrid instruments plus preferred stock divided by FFO plus gross interest paid plus preferred dividends plus rental expense.
- Interest Cover: FFO plus gross interest paid plus preferred dividends divided by gross interest paid plus preferred dividends.
- FCF/Revenue: FCF after dividends divided by revenue.
- FFO/Debt: FFO divided by gross debt plus lease adjustment minus equity credit for hybrid instruments plus preferred stock.

Fitch's expectations are based on the agency's internally produced, conservative rating case forecasts. They do not represent the forecasts of rated issuers individually or in aggregate. Key Fitch forecasts assumptions include:

- 1% utility sales growth over 2012–2013 and 1.5% over 2014–2015.
- Constructive outcome in FPL's pending rate case with step-up increases as power generation projects become operational.
- Inclusion of known and announced U.S. wind, Canadian wind, and solar projects.
- Adjustments made for nonrecourse projects as:
  - o Consolidated debt and interest expense is adjusted for the nonrecourse debt.
  - o Consolidated EBITDA and FFO exclude EBITDA and PTC contribution from the nonrecourse projects and include the distributable cash flow from these projects.

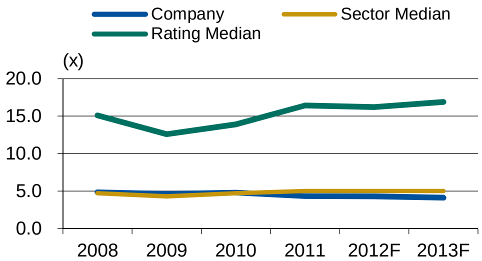
Key Metrics

Leverage: Total Adj. Debt/Op. EBITDAR



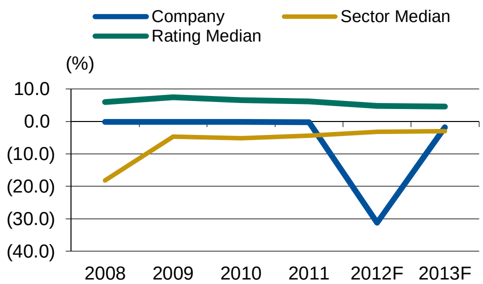
F – Forecast.
Source: Company data, Fitch.

Int. Coverage: Op. EBITDA/ Gross Interest Expense



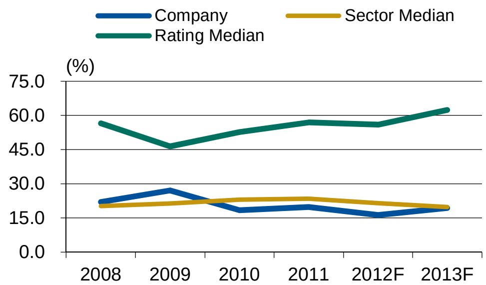
F – Forecast.
Source: Company data, Fitch.

FCF/Revenues



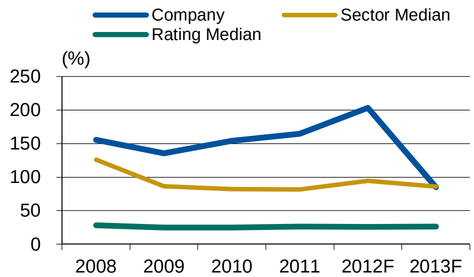
F – Forecast.
Source: Company data, Fitch.

FFO/Debt



F – Forecast.
Source: Company data, Fitch.

Capex/CFO



F– Forecast.
Source: Company data, Fitch.

Capex — FPL

(As of June 30, 2012)

($ Mil.)	2H 2012	2013	2014	2015	2016
Generation					
New	970	815	695	300	160
Existing	285	645	660	560	435
T&D	420	690	690	660	705
Nuclear Fuel	85	125	205	250	250
General and Other	120	190	120	80	90
Total	**1,880**	**2,465**	**2,370**	**1,850**	**1,640**

T&D – Transmission and distribution.
Source: Company data, Fitch.

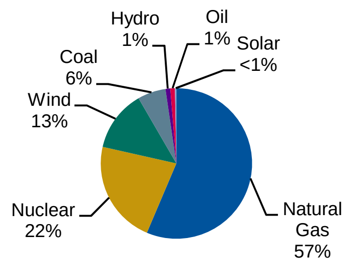
Capex — Energy Resources

(As of June 30, 2012)

($ Mil.)	2H12	2013	2014	2015	2016
Wind	1,350	125	20	10	5
Solar	700	760	185	10	—
Nuclear	185	275	260	265	285
Other	135	160	90	100	95
Total	**2,370**	**1,320**	**555**	**385**	**385**

T&D – Transmission and distribution.
Source: Company data, Fitch.

NEE 2011 Fuel Mix



Source: Company data, Fitch.

Company Profile

Currently, approximately 78% of NEE's EBITDA is generated from stable, regulated, and contracted assets. Fitch expects this proportion to increase to 84% by 2014, driven by significant rate base expansion at FPL and commissioning of a regulated transmission line in Texas. After several years of pursuing growth at its nonregulated businesses through new wind additions and acquisitions, management is now pursuing growth at its regulated businesses. In Fitch's view, this is being driven by three factors:

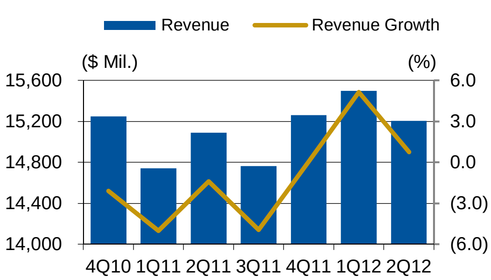
- The natural slowdown of new wind projects as the industry faces expiration of government subsidiaries, such as investment and production tax credits by the end of 2012. There remains tremendous uncertainty whether these subsidies will be extended in the current political climate.
- Weak wholesale power prices due to a fall in natural gas prices and the possibility of a likely prolonged commodity downturn have reduced the attraction of investing in merchant power generation assets.
- FPL is pursuing significant rate base expansion opportunities as it seeks to modernize several of its older gas-fired generation assets and uprate its nuclear generation capabilities. The regulatory climate in Florida has improved substantially, which raises the likelihood of achieving a constructive outcome in the pending rate case, in Fitch's opinion.

Business Trends

Utility

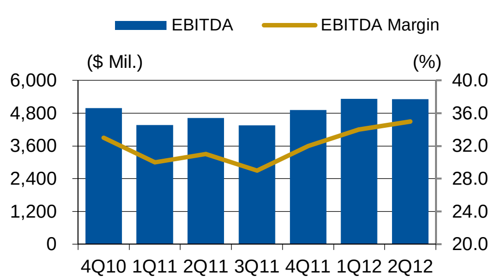
The Florida economy continues to improve, and several economic trends such as the unemployment rate and housing data continue to bottom out after a prolonged decline. Fitch is assuming that growth in customer accounts and energy sales at FPL will gradually return over the next three to four years, creating a more favorable utility operating environment. The regulatory construct in Florida is now on the mend after turning acrimonious in 2010. A majority of the commissioners at the FPSC are new, and the recent rate decisions for other Florida utilities have been constructive.

Revenue Dynamics



Source: Company data, Fitch.

EBITDA Dynamics



Source: Company data, Fitch.

Non-Utility

A highly hedged portfolio of generation assets mitigates Energy Resources' exposure to a persistently weak power price environment led by weakness in natural gas prices and a still recovering power demand. In August 2012, Fitch lowered its natural gas price deck to \$2.50/million British thermal units (mmBtu), \$2.75/mmBtu, and \$3.25/mmBtu for 2012, 2013, and 2014, respectively, a \$0.50/mmBtu–0.75/MMBtu reduction from its prior price deck. The uncertainty regarding PTCs extension beyond 2012 is likely to lead to a significant slowdown in new wind projects in the U.S.

Pension Analysis

Pension Analysis

	2011	2010
PBO (Under)/Over Funded Status ($ Mil.)	999	1,239
Pension Funded Analysis (%)	147.06	162.14
Estimated Pension Outflows/(FFO+Pension Contribution) (%)	1.51	1.67

Source: Company data, Fitch.

Financial Summary — NextEra Energy, Inc.

($ Mil.)	2008	2009	2010	2011	LTM Ended 6/30/12
Fundamental Ratios (x)					
FFO/Interest Expense	4.86	5.84	4.40	4.72	4.69
CFO/Interest Expense	4.93	5.76	4.64	4.54	4.37
FFO/Debt (%)	22.10	27.17	18.49	19.83	19.01
Operating EBIT/Interest Expense	3.27	2.76	3.09	3.00	3.30
Operating EBITDA/Interest Expense	4.83	4.61	4.79	4.33	4.52
Operating EBITDAR/(Interest Expense + Rent)	4.83	4.61	4.79	4.33	4.52
Debt/Operating EBITDA	3.62	3.86	3.84	4.33	4.30
Common Dividend Payout (%)	43.56	47.43	42.05	47.84	44.84
Internal Cash/Capital Expenditures (%)	50.57	60.91	50.80	46.74	38.41
Capital Expenditures/Depreciation (%)	391.62	347.97	331.03	438.65	546.08
Profitability					
Adjusted Revenues	16,339	15,575	15,249	15,260	15,204
Net Revenues	7,927	8,170	9,007	9,004	9,491
Operating and Maintenance Expense	2,527	2,649	2,877	3,002	3,108
Operating EBITDA	4,132	4,291	4,982	4,915	5,311
Depreciation and Amortization Expense	1,337	1,726	1,766	1,511	1,428
Operating EBIT	2,795	2,565	3,216	3,404	3,883
Gross Interest Expense	856	930	1,041	1,135	1,175
Net Income for Common	1,639	1,615	1,957	1,923	2,143
Operating and Maintenance Expense % of Net Revenues	31.88	32.42	31.94	33.34	32.75
Operating EBIT % of Net Revenues	35.26	31.40	35.71	37.81	40.91
Cash Flow					
Cash Flow from Operations	3,362	4,424	3,793	4,018	3,956
Change in Working Capital	54	(74)	258	(207)	(385)
Funds From Operations	3,308	4,498	3,535	4,225	4,341
Dividends	(714)	(766)	(823)	(920)	(961)
Capital Expenditures	(5,236)	(6,006)	(5,846)	(6,628)	(7,798)
FCF	**(2,588)**	**(2,348)**	**(2,876)**	**(3,530)**	**(4,803)**
Net Other Investment Cash Flow	(461)	183	562	145	(347)
Net Change in Debt	3,317	1,739	1,825	2,279	3,511
Net Equity Proceeds	41	198	569	139	459
Capital Structure					
Short-Term Debt	1,865	2,020	`889	1,349	1,515
Long-Term Debt	13,103	14,532	18,225	19,954	21,322
Total Debt	**14,968**	**16,552**	**19,114**	**21,303**	**22,837**
Total Hybrid Equity and Minority Interest	1,506	1,764	1,176	1,176	1,551
Common Equity	11,681	12,967	14,461	14,943	15,788
Total Capital	**28,156**	**31,284**	**34,752**	**37,423**	**40,177**
Total Debt/Total Capital (%)	53.16	52.91	55.00	56.93	56.84
Total Hybrid Equity and Minority Interest/Total Capital (%)	5.35	5.64	3.39	3.14	3.86
Common Equity/Total Capital (%)	41.49	41.45	41.61	39.93	39.30

Note: Debt numbers have been adjusted for storm securitization bonds and 50% equity credit to hybrid securities.
Source: Company data, Fitch.

The ratings above were solicited by, or on behalf of, the issuer, and therefore, Fitch has been compensated for the provision of the ratings.

Filed: 2013-03-28
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Board Staff #2 (UCT)
Attachment 2

STANDARD & POOR'S

Global Credit Portal®
RatingsDirect®

April 6, 2012

NextEra Energy Inc.

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NextEra Energy Inc.

Major Rating Factors

Corporate Credit Rating

A-/Stable/--

Strengths:

- High-quality electric utility that generates steady earnings and cash flows;
- Active efforts to sustainably reduce commodity price risk exposure in highly diversified unregulated activities;
- Low regulatory risk in Florida; and,
- Relatively strong service territory with good customer growth prospects and a predominantly residential and commercial base.

Weaknesses:

- Aggressive capital spending plans that stress financial metrics;
- Dependence on natural gas to generate electricity in Florida; and
- Higher-risk operations and less dependable cash flows from merchant generation, energy trading, and other unregulated activities.

Rationale

Diversified energy holding company NextEra Energy Inc.'s credit fundamentals on its regulated utility side have been among the strongest in the U.S., due primarily to low regulatory risk and an attractive service territory with healthy economic growth and a sound business environment. Both of those pillars have been shaken in recent years as Florida, and subsidiary Florida Power & Light's (FP&L) service territory in particular, suffered during the recession, and regulators have responded in ways that reflect greater political influence over regulatory decisions. Although the company has found maintaining financial strength despite mild regulatory upheaval and a moribund economy in Florida to be challenging, its actions to rebuild its regulatory risk profile have been effective. More importantly, the proportion of NextEra's unregulated businesses--the riskier merchant generation, marketing, and trading activities--could increase, which could further erode its consolidated business risk profile.

Standard & Poor's Ratings Services' ratings on NextEra reflect the strength of the regulated cash flows from integrated electric utility FP&L, and the diverse and substantial cash-generation capabilities of its unregulated operations at subsidiary NextEra Energy Resources (NER). FP&L represents about half of the consolidated credit profile and has better business fundamentals than most of its integrated electric peers, with a better-than-average service territory, sound operations, and a credit-supportive regulatory environment in which the company has been able to manage its regulatory risk very well. A willingness to expand through acquisitions, fluctuating cash flows from NER's rapidly expanding portfolio of merchant generation assets and growing marketing and trading activities, and significant exposure at the utility to natural gas detract from credit quality, in our view.

We characterize NextEra's business risk profile as "strong" and its financial risk profile as "intermediate" (as our criteria define the terms).

NextEra's business risk profile is anchored by the company's core electric utility operations in Florida, which exhibit proficiency in almost every area of analysis. The service territory has historically fared better than most of the rest of the country despite its lagging performance during the recession, the customer mix is mostly residential and commercial, costs and rates are low, and reliability and customer satisfaction are high. While Florida is not immune to overall economic trends, we expect the state to attract new residents and jobs over the long term and resume an above-average growth trajectory. NextEra's large and growing reliance on natural gas to fuel utility generation could eventually turn from an advantage (because of its favorable environmental status and currently low prices) to a weakness if gas prices are erratic over time.

FP&L has managed regulatory risk, the most important risk a utility faces, well. Despite a slight rise in regulatory risk in reaction to weak economic conditions amid keener attention in the political arena, the company has maintained the utility's financial performance and credit metrics and has stabilized its regulatory risk. FP&L has filed a new rate case aimed at a 7% base-rate increase (2.6% net of a proposed fuel clause decrease) to take effect when a rate freeze expires at the end of 2012. The conduct and outcome of the case will be an effective gauge of the state's regulatory environment.

NER, the main subsidiary under unregulated NextEra Energy Capital Holdings Inc., engages in electric generation, marketing, and trading throughout the U.S. NER's focus is on geographic and fuel diversity and on developing environmentally advantageous facilities that benefit from public policy trends. The merchant generator's capacity of almost 16,600 megawatts consists of more than half wind turbines, one-quarter natural-gas-fired stations, and the rest mainly nuclear facilities. More than three-quarters of the wind projects and almost 60% of the total portfolio operate under largely fixed-price, long-term contracts. The rest of the portfolio, including one nuclear plant, is merchant capacity that can be exposed to market prices for its output. While a policy of actively hedging the commodity price risk of plant inputs and outputs helps to reduce the risks associated with merchant energy activities, NER faces an inherent level of commodity price risk. In addition, NER's extensive project financing (approximately 46% of installed capacity) of its assets diminishes its cash flow quality, but this is offset by lower financial risk. NER's risks permanently hinder NextEra's credit quality, especially in light of the influence that marketing and high-risk proprietary trading results have on NER's earnings and cash flows.

We believe the governance and financial policies for managing risk are adequate. NextEra's financial risk profile is characterized by acceptable credit metrics, "adequate" liquidity under our criteria, and a management attitude toward credit quality that supports ratings. Importantly, sound but complex financial structures employed at the project level substantiate significant off-credit treatment of largely nonrecourse debt at NextEra. Any indication that management is using or is willing to use its own financial resources to aid a troubled project in support of strategic objectives could lead Standard & Poor's to reevaluate the adjustments we make to NextEra's reported debt. We also factor in large adjustments to the credit analysis regarding hybrid debt instruments and power-purchase agreements at FP&L. Adjusted credit metrics in current economic and market conditions support the intermediate financial profile. We expect the adjusted metrics to dip slightly in the near term and then return to historical levels, including funds from operations (FFO) to debt of around 25% and debt to capitalization about 50%.

Liquidity

The short-term rating on NextEra is 'A-2' and largely reflects our long-term issuer credit rating on the company and the stable regulated utility operations that substantially contribute to cash flows. Liquidity is "adequate" under Standard & Poor's corporate liquidity methodology, which categorizes liquidity in five standard descriptors.

The company's projected sources of liquidity, mostly operating cash flow and available bank lines, exceed its projected uses, mainly necessary capital expenditures, debt maturities, and common dividends, by more than 1.2x.

NextEra's ability to absorb high-impact, low-probability events with limited need for refinancing, its flexibility to lower capital spending or sell assets, its sound bank relationships, its solid standing in credit markets, and its generally prudent risk management further support our assessment of its liquidity as adequate.

Debt maturities total about $800 million in the next 12 months. The company has a $6.6 billion master revolving credit facility maturing in 2017 and more than $8 billion in total facilities, with about $4.7 billion currently available.

NextEra manages the liquidity needs of all its subsidiaries.

Liquidity is adequate based on the following factors and assumptions:

- We expect the company's liquidity sources (including FFO and credit facility availability) over the next 12 months to exceed its uses by more than 1.2x.
- Debt maturities over the next year are manageable.
- Even if EBITDA declines by 15%, we believe net sources will be well in excess of liquidity requirements.
- The company has good relationships with its banks, in our assessment, and has a good standing in the credit markets.

In our analysis, based on information available as of Dec. 31, 2011, we assumed liquidity of about $8.9 billion over the next 12 months, consisting of projected FFO and availability under the credit facility. We estimate the company could use up to $7 billion during the same period for capital spending, debt maturities, and shareholder dividends. NextEra's credit agreement includes a financial covenant limiting the consolidated debt-to-capitalization ratio, with which the company was compliant as of June 30, 2011.

Recovery analysis

We assign recovery ratings to FMBs issued by investment-grade U.S. utilities, which can result in issue ratings being notched above an issuer credit rating (ICR) on a utility depending on the rating category and the extent of the collateral coverage. We base our investment-grade FMB recovery methodology on the ample historical record of 100% recovery for secured bondholders in utility bankruptcies and on our view that the factors that supported those recoveries (the limited size of the creditor class, and the durable value of utility rate-based assets during and after a reorganization, given the essential service provided and the high replacement cost) will persist. Under our recovery criteria, when assigning issue ratings to utility FMBs, we consider our calculation of the maximum amount of FMB issuance under the utility's indenture or other legally binding limitations relative to our estimate of the value of the collateral pledged to bondholders, management's stated intentions on future FMB issuance, as well as any regulatory limitations on bond issuance. FMB ratings can exceed an ICR on a utility by up to one notch in the 'A' category, two notches in the 'BBB' category, and three notches in speculative-grade categories.

FP&L's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+', which indicates our expectation for 100% recovery in a default scenario, and an issue rating one notch above the ICR.

Outlook

Our rating outlook on NextEra and its subsidiaries is stable and reflects a business profile that is equally affected by higher-risk merchant energy activities and a utility that still presents a better credit profile than its peers. We would consider a lower rating if regulatory risk worsened, operational efficiency at NER deteriorated, investment decisions at NER demonstrated a shift in risk appetite, or financial performance declined due to permanent changes in the Florida economy or merchant energy markets. We would consider a higher rating if a dramatic, sustainable shift in Florida's economic, political, and regulatory environment is accompanied by affirmative steps to reduce risk at NER.

We also base the stable outlook in part on Standard & Poor's baseline forecast that NextEra will attain adjusted FFO to debt of about 17% and adjusted debt to capital of about 52% over the near term, with those metrics improving thereafter. Although year-to-year fluctuations in weather (including hurricanes), fuel cost recovery, and burdensome spending on large solar projects may temporarily affect metrics, we expect the company to adapt its financial risk management and the pace of its capital spending to account for these and other factors so it can achieve better metrics. We could lower the ratings if the company falls short of these expectations.

Accounting

NextEra's and FP&L's financial statements are prepared under U.S. generally accepted accounting principles and audited by independent auditors Deloitte & Touche LLP, which issued an unqualified opinion. NextEra employs regulatory accounting under Statement of Financial Accounting Standards No. 71 for regulated utility FP&L, which permits the company to defer recognition of certain revenues and expenses in accordance with future probable regulatory decisions. As of Dec. 31, 2011, NextEra had about $1.8 billion of regulatory assets and $4.3 billion of regulatory liabilities on a balance sheet that contained $57 billion of total assets. It is uncommon for a utility to have greater regulatory liabilities than assets.

NextEra relies on tax incentives, including direct tax credits, in NER's project development efforts. Tax credits underpin the economics of the projects, and NextEra guarantees the payment of production tax credits to projects that have been funded by third parties in project financings. Deferred tax assets, in the form of carryforwards of tax credits and net operating losses, have been growing at an accelerated rate on NextEra's balance sheet, totaling about $2.1 billion in 2011. To realize these tax benefits, the company must, among other things, continue to produce growing taxable income to use the carryforwards. If the deferred tax asset grows unabated, we could make an analytical adjustment in our metric calculation if we eventually conclude that the company is unlikely to fully realize the tax benefit.

In analyzing the company's financial profile, Standard & Poor's makes several off-balance-sheet adjustments that are shown in the reconciliation table below. We treat NER's fossil-fuel-based projects as nonessential to the company's strategy. We remove the nonrecourse debt and related interest in our adjusted numbers. However, we consider the renewables portfolio to be an integral part of its growth strategy, so we deconsolidate only 75% of related nonrecourse project debt and interest in our adjustments. In addition, we remove associated effects on the reported income and cash flow statements and replace them with the pro rata share of distributable cash flow of the projects. Credit metrics fully reflect debt related to projects under construction and subject to completion guarantees. As of year-end 2011, we removed approximately $4 billion of nonrecourse debt from the balance sheet.

Other adjustments include a reduction in debt and interest expense for storm recovery bonds issued to securitize hurricane damage costs (which the company services through a separate, non-bypassable, legislatively mandated rate mechanism) and adjustments to reflect the equity treatment on hybrid debt securities in accordance with our criteria on hybrid capital. We add about $166 million of a debt-like obligation to the balance sheet to quantitatively capture the risks associated with proprietary trading activities. Also, we regard purchased-power agreements as fixed obligations and assign a portion of the value of the payments based on the risk factor as debt and impute an associated interest charge in calculating the adjusted coverage ratios. We use a 25% risk factor, reflecting the recovery of these costs through an adjustment clause, and apply a discount rate equal to the utility's average cost of debt to the fixed capacity payments. We impute a debt-like obligation of approximately $950 million to the balance sheet.

Rating Methodology

We base our ICRs on NextEra, FP&L, and Holdings on the consolidated credit profile of the entire NextEra conglomerate of companies, which is almost equally influenced by the utility and unregulated energy operations. We rate the unsecured debt at Holdings, which is unconditionally guaranteed by the parent and is effectively holding company debt, one notch below the ICR because of structural subordination. Although Holdings' debtholders would have access to assets apart from the utility in liquidation, we apply strict notching guidelines because of the extensive use of project-level debt and the complexity of the financing arrangements throughout Holdings. We rate the first mortgage bonds at FP&L one notch above the ICR in accordance with the recovery analysis detailed above.

Related Criteria And Research

- Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Standard & Poor's Updates Its U.S. Utility Regulatory Assessments, March 12, 2010
- Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- Assessing U.S. Utility Regulatory Environments, Nov. 7, 2008
- Criteria: Changes To Collateral Requirements For '1+' Recovery Ratings On U.S. Utility First Mortgage Bonds, Sept. 6, 2007

Table 1

NextEra Energy Inc. -- Peer Comparison

Industry Sector: Energy

	NextEra Energy Inc.	**Entergy Corp.**	**Dominion Resources Inc.**	**Public Service Enterprise Group Inc.**	**Exelon Corp.**
Rating as of April 6, 2012	A-/Stable/--	BBB/Negative/--	A-/Stable/A-2	BBB/Positive/A-2	BBB/Stable/A-2
	--Average of past three fiscal years--				
(Mil. $)					
Revenues	15,119.7	11,082.1	14,902.3	11,423.0	17,904.0
EBITDA	4,396.8	3,529.7	4,699.9	3,731.9	6,734.6
Net income from cont. oper.	1,824.5	1,296.2	1,886.0	1,514.3	2,588.0
Funds from operations (FFO)	3,897.7	3,171.3	3,299.8	2,788.6	5,912.1
Capital expenditures	3,948.2	2,707.2	3,601.2	1,979.6	3,700.0
Free operating cash flow	(58.2)	517.1	(495.7)	977.0	2,013.5
Dividends paid	920.8	600.3	1,150.5	686.3	1,396.5
Discretionary cash flow	(979.0)	(83.2)	(1,646.2)	290.7	617.0
Cash and short-term investments	305.7	1,232.8	70.7	469.6	1,556.0

Table 1

NextEra Energy Inc. -- Peer Comparison (cont.)

Debt	15,887.2	13,687.4	19,263.1	8,858.2	18,717.7
Preferred stock	1,427.5	150.4	996.6	26.7	198.0
Equity	15,918.8	8,840.8	12,637.4	9,380.4	13,728.3
Debt and equity	31,806.0	22,528.2	31,900.5	18,238.6	32,446.0
Adjusted ratios					
EBITDA margin (%)	29.1	31.9	31.5	32.7	37.6
EBIT interest coverage (x)	3.9	3.2	3.6	6.5	5.7
Return on capital (%)	7.8	8.7	10.5	14.3	14.1
FFO int. cov. (X)	6.7	4.5	4.1	6.7	7.2
FFO/debt (%)	24.5	23.2	17.1	31.5	31.6
Free operating cash flow/debt (%)	(0.4)	3.8	(2.6)	11.0	10.8
Discretionary cash flow/debt (%)	(6.2)	(0.6)	(8.5)	3.3	3.3
Net cash flow/capex (%)	75.4	95.0	59.7	106.2	122.0
Debt/EBITDA (x)	3.6	3.9	4.1	2.4	2.8
Total debt/debt plus equity (%)	50.0	60.8	60.4	48.6	57.7
Return on capital (%)	7.8	8.7	10.5	14.3	14.1
Return on common equity (%)	12.5	13.8	15.7	16.5	19.5
Common dividend payout ratio (un-adj.) (%)	45.8	46.2	53.3	45.4	58.2

Table 2

NextEra Energy Inc. -- Financial Summary

Industry Sector: Energy					
	--Fiscal year ended Dec. 31--				
	2011	**2010**	**2009**	**2008**	**2007**
Rating history	A-/Stable/--	A-/Stable/--	A/Stable/--	A/Stable/--	A/Stable/--
(Mil. $)					
Revenues	14,926.7	15,009.0	15,423.4	15,983.2	14,861.5
EBITDA	4,199.8	4,804.3	4,186.3	3,882.5	3,281.7
Net income from continuing operations	1,923.0	1,935.5	1,615.0	1,436.2	1,263.3
Funds from operations (FFO)	3,817.2	3,596.3	4,279.6	3,185.5	3,558.6
Capital expenditures	5,937.4	2,970.2	2,937.2	2,273.2	1,875.9
Dividends paid	1,022.3	905.0	835.1	772.5	700.1
Debt	17,943.5	15,214.5	14,503.5	13,798.8	10,770.2
Preferred stock	1,929.5	1,176.5	1,176.5	1,005.0	1,004.5
Equity	16,872.5	16,390.5	14,493.5	12,686.0	11,739.5
Debt and equity	34,816.0	31,605.0	28,997.0	26,484.8	22,509.7
Adjusted ratios					
EBITDA margin (%)	28.1	32.0	27.1	24.3	22.1
EBIT interest coverage (x)	3.8	4.4	3.5	3.5	3.2
FFO int. cov. (x)	6.3	6.4	7.4	5.8	6.3

Table 2

NextEra Energy Inc. -- Financial Summary (cont.)					
FFO/debt (%)	21.3	23.6	29.5	23.1	33.0
Discretionary cash flow/debt (%)	(18.7)	(0.1)	3.0	1.4	9.2
Net cash flow/capex (%)	47.1	90.6	117.3	106.2	152.4
Debt/debt and equity (%)	51.5	48.1	50.0	52.1	47.8
Return on capital (%)	7.2	8.6	7.5	8.3	8.4
Return on common equity (%)	12.0	13.5	12.1	11.7	11.5
Common dividend payout ratio (un-adj.) (%)	47.8	42.5	47.4	50.3	51.8

Table 3

Reconciliation Of NextEra Energy Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)

	--Fiscal year ended Dec. 31, 2011--									
NextEra Energy Inc. reported amounts										
	Debt	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	22,967.0	14,943.0	15,341.0	4,996.0	3,378.0	1,035.0	4,074.0	4,074.0	920.0	6,004.0
Standard & Poor's adjustments										
Equity-like hybrids	(753.0)	753.0	--	--	--	(20.3)	20.3	20.3	20.3	--
Intermediate hybrids reported as debt	(1,176.5)	1,176.5	--	--	--	(82.0)	82.0	82.0	82.0	--
Postretirement benefit obligations	--	--	--	(121.0)	(121.0)	--	52.7	52.7	--	--
Capitalized interest	--	--	--	--	--	124.0	(124.0)	(124.0)	--	(124.0)
Share-based compensation expense	--	--	--	49.0	--	--	--	--	--	--
Nonrecourse debt	(3,993.0)	--	(343.0)	(343.0)	(343.0)	(343.0)	--	--	--	--
Securitized utility cost recovery	(487.0)	--	(71.3)	(71.3)	(26.3)	(26.3)	(45.0)	(45.0)	--	--
Power purchase agreements	922.0	--	--	105.1	47.8	47.8	57.4	57.4	--	57.4
Reclassification of nonoperating income (expenses)	--	--	--	--	211.0	--	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	207.0	--	--
US decommissioning fund contributions	--	--	--	--	--	--	(92.0)	(92.0)	--	--
Debt - Accrued interest not included in reported debt	464.0	--	--	--	--	--	--	--	--	--
EBITDA - Other	--	--	--	(415.0)	(415.0)	--	--	--	--	--
D&A - Impairment charges/(reversals)	--	--	--	--	51.0	--	--	--	--	--
FFO - Other	--	--	--	--	--	--	(415.0)	(415.0)	--	--

Table 3

Reconciliation Of NextEra Energy Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $) (cont.)

Total adjustments	(5,023.5)	1,929.5	(414.3)	(796.2)	(595.5)	(299.7)	(463.8)	(256.8)	102.3	(66.6)

Standard & Poor's adjusted amounts

	Debt	Equity	Revenues	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid	Capital expenditures
Adjusted	17,943.5	16,872.5	14,926.7	4,199.8	2,782.5	735.3	3,610.2	3,817.2	1,022.3	5,937.4

Ratings Detail (As Of April 6, 2012)	
NextEra Energy Inc.	
Corporate Credit Rating	A-/Stable/--
Corporate Credit Ratings History	
11-Mar-2010	A-/Stable/--
14-Jan-2010	A/Watch Neg/--
26-Oct-2006	A/Stable/--
Business Risk Profile	Strong
Financial Risk Profile	Intermediate
Debt Maturities	
2012: $808 mil. 2013: $2.4 bil. 2014: $2.0 bil. 2015: $1.8 bil. 2016: $695 mil.	
Related Entities	
Florida Power & Light Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
FPL Group Capital Trust I	
Preferred Stock (1 Issue)	BBB
NextEra Energy Capital Holdings Inc.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Junior Subordinated (1 Issue)	BBB
Senior Unsecured (1 Issue)	BBB+

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

MOODY'S
INVESTORS SERVICE

Credit Opinion: NextEra Energy, Inc.

Global Credit Research - 05 Dec 2012

Juno Beach, Florida, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured Shelf	(P)Baa1
Subordinate Shelf	(P)Baa2
Pref. Shelf	(P)Baa3
NextEra Energy Capital Holdings, Inc.	
Outlook	Stable
Senior Unsecured	Baa1
Jr Subordinate	Baa2
BACKED Pref. Shelf	(P)Baa3
Commercial Paper	P-2
Florida Power & Light Company	
Outlook	Stable
Issuer Rating	A2
First Mortgage Bonds	Aa3
Senior Secured Shelf	(P)Aa3
Senior Unsecured Shelf	(P)A2
Subordinate Shelf	(P)A3
Pref. Shelf	(P)Baa1
Commercial Paper	P-1
FPL Group Capital Trust I	
Outlook	Stable
BACKED Pref. Stock	Baa2

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Key Indicators

[1]**NextEra Energy, Inc.**

	LTM 9/30/12	2011	2010	2009
(CFO Pre-W/C + Interest) / Interest	**4.8x**	**4.8x**	**4.5x**	**6.3x**
(CFO Pre-W/C) / Debt	**16%**	**19%**	**18%**	**26%**
RCF / Debt	**13%**	**16%**	**13%**	**21%**
FCF / Debt	**(23%)**	**(16%)**	**(14%)**	**(13%)**

[1] All ratios calculated in accordance with the Unregulated Utilities and Power Companies Rating Methodology using Moody's standard adjustments.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

- Diverse, low carbon, mostly contracted or hedged generating portfolio at NextEra Energy Resources

- High, growing debt levels at its unregulated subsidiaries, much of which is either directly guaranteed by NextEra Energy or has significant recourse characteristics

- Consolidated cash flow coverage ratios that are weak for a Baa1 rated hybrid power company, but we expect them to improve in 2013 as the company slows the growth of its wind project portfolio

- Shale gas drilling, energy marketing and trading, Texas retail, and Spanish solar businesses increase risk profile

- Stabilized Florida utility political and regulatory environment with important base rate case pending

- Liquidity is constrained with high levels of guarantees and letters of credit outstanding, large potential rating triggered collateral calls, and over $3.6 billion of debt and CP due over the next twelve months

Corporate Profile

NextEra Energy, Inc. (NextEra, Baa1 Issuer Rating, stable outlook) is one of the largest power and utility companies in the U.S. with annual revenues of over $15 billion. NextEra Energy Capital Holdings, Inc. (Capital Holdings, Baa1 senior unsecured, stable outlook) finances the company's unregulated operations, which include wind, solar, and other independent power projects, as well as several diversified energy businesses, through its wholly owned subsidiary, NextEra Energy Resources (unrated). NextEra Energy is also the parent of Florida Power and Light Company (FPL, A2 Issuer Rating, stable outlook), a vertically integrated utility with a service territory that includes many of the Florida coastal communities, and Lone Star Transmission LLC (unrated), a regulated transmission company in Texas.

SUMMARY RATING RATIONALE

NextEra's rating reflects its position as the parent of both one of the largest unregulated wholesale generating and diversified energy companies in the U.S. and a fully regulated vertically integrated Florida utility. Over the last decade, NextEra has evolved from being solely a regulated Florida utility into a major, international energy company with its Florida regulated utility declining in importance as a credit driver for the consolidated entity. NextEra's business mix now includes a large and growing portfolio of unregulated wholesale generating assets, as well as a collection of diversified energy businesses including shale gas drilling, energy marketing and trading, Texas retail energy, and a Spanish solar project. As a result, these non-utility unregulated operations are the primary credit driver of the company's consolidated credit profile, and issues associated with some of these businesses have kept the company relatively weakly positioned at the Baa1 rating level. Because of its status as a hybrid power company with both unregulated and regulated utility operations, NextEra is analyzed under both Moody's Unregulated Power Companies and Regulated Electric and Gas Utilities rating methodologies, with the Unregulated Power methodology more applicable.

DETAILED RATING CONSIDERATIONS

- Diverse, low carbon, mostly contracted or hedged generating portfolio at NextEra Energy Resources

The company's unregulated generating portfolio at NextEra Energy Resources consists of approximately 16,899 MW of generating capacity in 23 states, Canada, and Spain. Growth in 2012 has come primarily from wind and solar project development. Long-term growth of its U.S. wind portfolio beyond 2012 should be more limited predominantly due to the scheduled termination of government tax incentives at the end of the year, but also because of low power prices, increased competition, and ongoing uncertainty over renewable portfolio standards and the timing of potential carbon regulation. However, the company recently signed its first power purchase agreement for a 100 MW wind project in 2013, one that is not dependent on the extension of tax credits. The company is on target to add approximately 1,500 MW of new U.S. wind projects in 2012 and approximately 600 MW of Canadian wind generation between 2012 and 2015. It is also planning to add approximately 900 MW of new solar generation between 2012 and 2016.

In 2011, subsidiary NextEra Energy Resources completed the sale of four of its contracted natural gas-fired generating assets and one of its merchant natural gas generating assets. We viewed the sale of the contracted assets as modestly negative to overall credit quality in that it reduced the generation portfolio's diversity, as well as the percentage of contracted assets within the portfolio. The company's natural gas generating portfolio now consists predominantly of merchant generation in Texas, where it has 73% of its 2013 gross margin hedged as of September 7, 2012, the lowest of any of its generating assets. The sale also increased the proportion of more risky diversified activities in the company's overall business mix compared to its more traditional, lower risk contracted generating assets, which we view as having a lower business risk profile.

NextEra has also diversified into regulated transmission in Texas through its Lone Star subsidiary, which is constructing and will operate approximately 320 miles of 345 kV transmission lines in the state. In January 2012, Lone Star filed a petition with the Public Utilities Commission of Texas (PUCT) requesting rate increases of $14 million in 2012 and $110 million in 2013, a proposed regulatory return on equity of 11%, and a 52% equity ratio. In October 2012, the PUCT approved an annual revenue requirement for approximately $50 million of capital investment and O&M expenses. The annual revenue requirement reflects, among other things, an equity ratio of 40% and an allowed regulatory return on equity of 9.6%, well below the company's request and reflective of the challenging Texas regulatory environment. The remaining capital investment will be included in rates through an interim rate adjustment mechanism. We view this regulated transmission company as a small but positive contributor to NextEra's overall credit profile.

- High, growing debt levels at both Capital Holdings and NextEra Energy Resources that is either guaranteed by NextEra or has significant recourse characteristics

As NextEra Energy has emphasized the growth of its non-utility operations in recent years, debt levels at both Capital Holdings and NextEra Energy Resources have increased significantly and now together total $16.7 billion as of September 30, 2012 (on a Moody's adjusted basis), or 66% of the debt of the consolidated organization, up from $14.4 billion at year end 2011 and $13.3 billion at year end 2010. This considerable growth has diluted the value of the parent company guarantee of Capital Holdings debt over the years, as the parent now guarantees over $11 billion of the subsidiary's debt, including $1.1 billion of notes payable and commercial paper outstanding as of September 30, 2012.

An additional $6.5 billion of debt is characterized as "limited recourse" debt under subsidiary NextEra Energy Resources on the company's financial statements. Though this debt may not be directly guaranteed, much of it is tied to NextEra Energy and/or Capital Holdings in some way, either through sponsorship of the underlying projects; tax interrelationships including guarantees of production tax credits on wind projects; cash traps at some projects that are tied to rating levels of NextEra Energy or Capital Holdings, or through financial covenants at NextEra Energy itself. As a result, we include this limited recourse debt in our analytical approach and in our published financial ratios.

We note that this debt resides at both Capital Holdings and Energy Resources, two major entities that do not have separate audited SEC financial statements, which are filed only on a consolidated basis at NextEra Energy, Inc. We believe the level of financial and operational transparency at Capital Holdings and Energy Resources has not increased commensurately with their business risk profiles over the last several years. In addition to the lack of audited financials, these companies do not file or otherwise disclose their bank credit agreements, financial covenant requirements, or the level of cushion they may have under these covenants. The company also does not disclose individual project financial, cash flow or dividend information, making it difficult to judge the performance of its power project portfolio. NextEra management hosted a fixed income analyst meeting earlier this year to provide analysts with additional information on its unregulated businesses.

- Consolidated cash flow coverage metrics are weak for a Baa1 rated hybrid power company, but which we expect to improve in 2013 as the company slows the growth of its wind project portfolio

The company's consolidated financial performance and cash flow coverage metrics have historically been relatively stable and adequate for a company with a balanced mix of businesses, but have not strengthened as it has relied more on unregulated cash flows to service its growing debt obligations. The maintenance of current Baa1 ratings at both NextEra Energy and Capital Holdings are predicated on a strengthening of financial metrics and a lowering of leverage beginning in 2013 as it slows the growth of its wind project portfolio.

As the company has become more of a wholesale generating company, diversified into other energy related businesses, and expanded internationally, metrics have not strengthened to offset and mitigate the higher risk associated with these businesses. Over the last two years, the company has generated consolidated CFO pre-working capital interest coverage of 4.8x for the twelve months ending 9/30/12 and 4.8x in 2011, at the low end of the 3.6x to 6.9x rating range guidelines for a Baa rating under our Unregulated Power Companies rating methodology. In addition, the ratio of consolidated CFO pre-working capital to debt of 16.5% for the twelve months ended 9/30/12 and 18.9% in 2011 are well below the Baa rating range of 21% to 35% under that methodology. We note that utility FPL's metrics are well above the parameters outlined for its A2 Issuer Rating under our Regulated Utilities rating methodology, which offsets to some degree the consolidated company's weaker credit profile. The diverse and highly contracted nature of the generating portfolio also helps to mitigate risks associated with these low coverage ratios.

- Shale gas well drilling, energy trading and marketing, Spanish solar, and Texas retail businesses increase risk profile and further expansion of these businesses could pressure ratings

Over the last several years, NextEra Energy Resources has diversified away from being a predominantly domestic, asset focused wholesale power company with expansions into several non-asset based and international businesses. The company is actively growing its shale gas drilling business, with the 2013 gross margin from this business now projected to be between $200 and $320 million, up significantly from the $140 to $240 million range projected just a few months ago. We view this business as having a higher risk profile than the company's traditional wholesale generation business and believe the involvement of one of the leading "clean energy" companies in fracking, an environmentally controversial drilling practice, entails reputational and other intangible risks.

The company expanded its Houston based trading operations several years ago with the gross margin contribution from this business fluctuating widely in 2008 and 2009. The contribution of the trading business over the last three years has been lower because of reduced power market volatility and unfavorable market conditions. Late last year, the company relocated its gas trading operations from Houston to its corporate headquarters in Florida and indicated that it was lowering expectations for the business going forward. We view any movement away from energy trading and marketing as credit supportive.

The company's $1.2 billion Spanish solar project financing is facing challenges given deteriorating fiscal and economic conditions in Spain. The country is considering implementing new taxes on energy projects, as well as other changes that could reduce the financial attractiveness of owning renewable generation. These changes will likely lower the returns NextEra had expected on this project and could require additional equity infusions in the range of $40 to $50 million.

After a financially difficult summer in 2011 caused by extremely hot weather and substantial power price spikes, GEXA, the company's Texas retail business, experienced a more normal year in 2012. However, the company was negatively affected by mild weather and flat pricing that prevailed in Texas over the summer.

- Stabilization of utility FPL's political and regulatory environment with important base rate case pending

FPL operates under traditional rate of return regulation with strong cost recovery provisions in place. These include fuel and capacity clauses which are adjusted annually based on expected fuel and power prices and for prior period differences between projected and actual costs. FPL may also recover pre-construction and construction work in progress for nuclear capital expenditures and the FPSC earlier this month approved $398 million of revenue requirements related to recently completed nuclear uprates, as well as cost for new nuclear development projects. The company has also been able to recover costs associated with several new solar generating facilities since 2009. Additionally, FPL has an environmental cost recovery clause that is adjusted annually for capital spending and operating expenses related to emission controls.

On March 19, 2012, FPL filed for a two-step base rate increase consisting of a January 2013 increase of approximately $517 million plus an additional $174 million increase in June 2013 upon commercial operation of its repowered Cape Canaveral generating plant. The rate case requested an 11.5% ROE based upon a 46% equity to total capital ratio (on a GAAP basis), which compares to the 10% midpoint ROE the company is mandated under its current rate agreement. This represents the first rate case filed by the company since highly politicized rate proceedings in 2009 and early 2010 resulted in a rate outcome that was substantially less than the company had requested. This new rate case will be decided by an almost completely new Florida Public Service Commission (FPSC), with the turnover of four of the five commissioner seats since 2010.

In August, FPL and several intervenors proposed a settlement agreement that incorporates a $378 million base rate increase beginning in January 2013, an allowed ROE of 10.7% with a range of plus or minus 100 basis points, generation base rate adjustments (GBRA) upon commercial operation of the utility's three plant modernization projects (Cape Canaveral, Riviera, and Port Everglades), and flexibility in amortizing up to $400 million of its surplus depreciation reserve and a portion of its fossil dismantlement reserve. Florida's Office of Public Counsel has opposed the settlement. Evidentiary hearings on the settlement were completed at the end of November, with a decision by the FPSC due December 13. If the settlement is not approved, the FPSC is expected to rule on FPL's original rate case filing in January.

Given that not all of the intervenors in the case are party to the settlement and the ongoing opposition of the Public Counsel and others, the FPSC may not approve the settlement and instead choose to rule on the original filing. While we would view approval of the settlement as reasonably credit supportive, we would not consider a decision by the FPSC to consider the original rate case by itself to be a particularly negative development. In either case, the final outcome of the rate case will be an important indicator as to whether the utility regulatory environment in Florida has improved significantly since the company's last rate case outcome in 2010.

FPL continues to exhibit some of the stronger financial performance measures and cash flow coverage ratios in the industry, with ratios that are generally well above the parameters required for its rating under our Regulated Electric and Gas Utilities rating methodology, and this helps to support the rating of the parent company. These ratios include CFO pre-working capital interest coverage in the 6.0x to 8.0x range and CFO pre-working capital to debt in the 30% to 35% range in recent years. Its debt to capitalization of 33.1% at September 30, 2012 is among the lowest in the industry and the company maintains a fully funded pension plan, contributing to this low leverage profile (as Moody's adds pension underfunding to debt).

Liquidity Profile

NextEra maintains no bank credit facilities or other liquidity facilities at the parent company, but relies on bank revolving credit facilities at both of its major subsidiaries for liquidity ($4.6 billion at Capital Holdings and $3.2 billion at FPL). FPL maintains a significantly stronger liquidity profile than Capital Holdings, where liquidity has become increasingly constrained in recent years by substantially higher levels of guarantees issued, commercial paper and letters of credit outstanding, significant credit rating related collateral calls, and an energy trading and marketing business that could suddenly require additional liquidity.

Capital Holdings and Energy Resources also have a substantial $2.7 billion of debt due over the 12 months ending September 30, 2013, including $581 million of outstanding commercial paper, $521 million of short-term debt, and $1.6 billion of long-term debt. The level of commercial paper outstanding at Capital Holdings at September 30, 2012 was down from approximately $1 billion outstanding at December 31, 2011. At September 30, 2012, Capital Holdings and Energy Resources had approximately $1.3 billion of standby letters of credit; $170 million of surety bonds; and a substantial $13.6 billion notional amount of guarantees outstanding, of which approximately $8 billion have expiration dates over the next five years. FPL has very relatively few letters of credit, surety bonds, or guarantees outstanding.

Virtually all of the NextEra's letters of credit outstanding at September 30, 2012 were issued under Capital Holdings' credit facilities which, when combined with its currently outstanding commercial paper, utilizes nearly half of the company's $4.6 billion bank revolving credit facilities. Commercial paper outstanding at Capital Holdings has remained relatively high in the $1 billion range in 2012 as the company completes its aggressive wind project build program this year. The company has termed out some commercial paper during the year with portions of the over $2 billion of hybrid securities issued in 2012. Capital Holdings had $226 million of cash on hand as of September 30, 2012, down slightly from $339 million at December 31, 2011.

NextEra also has substantial exposure to collateral calls in the event of credit rating downgrades. If Capital Holdings and FPL's credit ratings were downgraded to BBB/Baa2, NextEra would be required to post collateral of approximately $350 million ($10 million at FPL). If Capital Holdings' and FPL's credit ratings were downgraded below investment grade, the company would be required to post collateral of approximately $2.2 billion ($500 million at FPL). This level of downgrade related collateral calls is above industry peers such as Constellation Energy (prior to its merger with Exelon) and Exelon Generation, whose collateral calls were $1.1 billion and $1.6 billion, respectively, if downgraded below investment grade (as of December 31, 2011). Moreover, additional NextEra contracts that do not have rating triggers but require the maintenance of certain financial measures or have other credit-related cross default triggers could require additional collateral of up to approximately $600 million ($100 million at FPL).

FPL's $3.2 billion of bank credit facilities support more manageable outstanding obligations, including $472 million of outstanding commercial paper as of September 30, 2012. FPL's bank revolving credit facilities are also available to support the purchase of $633 million of pollution control, solid waste disposal, and industrial development bonds in the event they are tendered and not remarketed. FPL has $452 million of long-term debt due over the next 12 months, including $400 million of first mortgage bonds due in February 2013.

Neither FPL nor Capital Holdings have a material adverse change clause in their bank credit facilities, although both have a debt to capitalization covenant, the calculation of which the company does not make public. The company reported that it was in compliance with these covenants at September 30, 2012.

Rating Outlook

The stable rating outlook reflects Moody's expectation that the growth of the company's power project businesses will moderate beyond 2012; that consolidated financial metrics will improve to levels more commensurate with a Baa1 rating; that debt levels at Capital Holdings and Energy Resources will not increase beyond current levels; that the company will maintain a high level of long-term contracts and hedges in place on its wholesale generating assets; and that it will not materially increase its shale gas drilling, energy marketing and trading, Texas retail, and Spanish solar businesses beyond current levels. The stable outlook also reflects the financial performance of FPL and our expectation that there will be a credit supportive outcome to the utility's pending rate case that maintains the utility's strong metrics and low leverage profile.

What Could Change the Rating - Up

A higher rating is unlikely over the near term but could be considered if the company materially reduces debt levels at Capital Holdings and/or Energy Resources; reduces or eliminates its diversified businesses; improves its liquidity position by reducing the level of contingent collateral and other potential calls on liquidity, or if cash flow coverage metrics increase to levels more in line with our parameters for a high Baa rated unregulated power company, including consolidated CFO pre-working capital to debt of 30% or higher and CFO pre-working capital to interest of 6.0x or higher.

What Could Change the Rating - Down

A downgrade could be considered if leverage continues to increase at Capital Holdings and/or Energy Resources; if there is any further expansion into diversified, higher risk businesses; if there is a significant energy trading loss; if liquidity at Capital Holdings tightens further from already constrained levels; if wind project development activities do not slow in 2013 as anticipated or if production tax credits are extended in the U.S.; if there is an unexpectedly adverse outcome to the utility's pending rate case; or if consolidated cash flow coverage metrics continue to remain weak for its current rating and risk profile, including CFO pre-working capital to debt below 20% or CFO pre-working capital interest coverage below 5.0x.

Rating Factors

NextEra Energy, Inc.

Power Companies [1][2]	**LTM 9/30/2012**			**Moody's 12-18 month Forward View* As of December 2012**	
Factor 1: Market Assessment, Scale and Competitive Position (20%)	**Measure**	**Score**		**Measure**	**Score**
a) Market and Competitive Position (15%)		Baa			Baa
b) Geographic Diversity (5%)		Aa			Aa
Factor 2: Cash Flow Predictability of Business Model (20%)					
a) Hedging strategy (10%)		A			A
b) Fuel Strategy and mix (5%)		A			A
c) Capital requirements and operatinal performance (5%)		A			A
Factor 3: Financial policy (10%)		Baa			Baa
Factor 4: Financial Strength - Key Financial Metrics (50%)					

a) CFO pre-WC + Interest / Interest (15%) (3yr Avg)	4.8x	Baa	5.0 - 5.5x	Baa
b) CFO pre-WC / Debt (20%) (3yr Avg)	18.0%	Ba	18 - 22%	Ba/Baa
c) RCF / Debt (7.5%) (3yr Avg)	16.9%	Baa	13 - 17%	Ba/Baa
d) FCF / Debt (7.5%) (3yr Avg)	-14.2%	B	0 - 10%	Ba
Rating:				
a) Indicated Rating from Grid		Baa2		Baa2
b) Actual Rating Assigned		Baa1		Baa1

Regulated Electric and Gas Utilities Industry [1][2]	**LTM 9/30/2012**		**Moody's 12-18 month Forward View* As of December 2012**	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Regulatory Framework		Baa		Baa
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		Baa		Baa
Factor 3: Diversification (10%)				
a) Market Position (5%)		A		A
b) Generation and Fuel Diversity (5%)		A		A
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				
a) Liquidity (10%)		A		Baa
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	4.8x	A	5.0 - 5.5x	A
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	18.0%	Baa	18 - 22%	Baa
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	13.7%	Baa	13 - 17%	Baa
e) Debt/Capitalization (3 Year Avg) (7.5%)	51.2%	Baa	50 - 53%	Baa
Rating:				
a) Indicated Rating from Grid		Baa1		Baa1
b) Actual Rating Assigned		Baa1		Baa1

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 9/30/2012 (LTM); Source: Moody's Financial Metrics

MOODY'S INVESTORS SERVICE

MOODY'S INVESTORS SERVICE

Credit Opinion: NextEra Energy Capital Holdings, Inc.

Global Credit Research - 10 Apr 2012

Juno Beach, Florida, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Senior Unsecured	Baa1
Jr Subordinate	Baa2
BACKED Pref. Shelf	(P)Baa3
Commercial Paper	P-2
Parent: NextEra Energy, Inc.	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured Shelf	(P)Baa1
Subordinate Shelf	(P)Baa2
Pref. Shelf	(P)Baa3

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Opinion

Rating Drivers

- Diverse, low carbon, mostly contracted or hedged generating portfolio

- High, growing debt levels

- Consolidated cash flow coverage ratios that are weak for a Baa1 rated hybrid power company

- Energy marketing and trading, shale gas drilling, Texas retail, and Spanish solar businesses have increased risk profile

- Liquidity is constrained by substantially higher levels of guarantees, commercial paper, and letters of credit issued during 2011

Corporate Profile

NextEra Energy Capital Holdings, Inc. (Capital Holdings, Baa1 senior unsecured, stable outlook) is a wholly owned subsidiary of NextEra Energy, Inc. (Baa1 Issuer Rating, stable outlook), one of the largest providers of electricity-related services in the U.S. with annual revenues of over $15 billion. Capital Holdings finances the company's unregulated operations, which include wind, solar, and other independent power projects, as well as several diversified energy businesses, under subsidiary NextEra Energy Resources (unrated). NextEra Energy is also the parent of Florida Power and Light Company (FPL, A2 Issuer Rating, stable outlook), a vertically integrated utility with a service territory that includes many of the Florida coastal communities, and Lone Star Transmission LLC (unrated), a Texas regulated transmission company.

SUMMARY RATING RATIONALE

Capital Holdings' Baa1 senior unsecured rating reflects the support of NextEra Energy (Baa1 Issuer Rating), which unconditionally guarantees all of its debt and payment obligations. Consequently, Capital Holding's rating partially reflects the consolidated financial strength of the entire NextEra Energy organization, which includes a large and growing portfolio of unregulated wholesale generating assets at its NextEra Energy Resources subsidiary and a collection diversified energy businesses including energy marketing and trading, shale gas drilling, Texas retail energy, and a Spanish solar project. Over the last decade, NextEra Energy has evolved from being predominantly a regulated Florida utility into a major, international energy company with its Florida regulated utility declining in importance as a credit driver of the company's consolidated credit profile. Issues related to some of its diversified businesses have weakened NextEra Energy's relative position at the Baa1 rating category over the last two years, although the company is not expected to grow these businesses further going forward. The company's liquidity position has become constrained during 2011 has it has substantially increased the level of guarantees, commercial paper, and letters of credit outstanding during the year, and is exposed potentially to large credit rating triggered collateral calls.

DETAILED RATING CONSIDERATIONS

- Diverse, low carbon, mostly contracted or hedged generating portfolio

The company's unregulated generating portfolio at NextEra Energy Resources consists of approximately 16,600 MW of generating capacity in 22 states, Canada, and Spain. Near-term growth in 2012 is expected to come primarily from wind and solar project development. Long-term growth of its U.S. wind portfolio beyond 2012 could be challenged predominantly due to the scheduled termination of government tax incentives at the end of the year, but also because of low power prices, increased competition, and ongoing uncertainty over renewable portfolio standards and the timing of potential carbon regulation. The company plans to add from 1,150 MW to 1,500 MW of new U.S. wind projects in 2012 and approximately 600 MW of Canadian wind projects between 2012 and 2015. It is also planning to add between 850 MW and 950 MW of new solar generation between 2012 and 2016. Included in these totals are the Genesis project (250 MW solar thermal), the McCoy project (250 MW solar PV), both located in California, as well as a 99.8 MW solar thermal facility in Spain. It is also a 50% owner of Desert Sunlight, a 550 MW solar PV facility also under construction in California.

NextEra Energy Capital Holdings also includes Lone Star, a regulated transmission business in Texas, which is constructing and will operate approximately 320 miles of 345 kv transmission lines and associated facilities in the state. Two substations and associated facilities with a total capital investment of approximately $60 million are expected to be placed into service in 2012, with the remaining facilities and lines expected to be placed into service in early 2013. In January 2012, Lone Star filed a rate case with the Public Utility Commission of Texas (PUCT) requesting rate increases of $14 million in 2012 and $110 million in 2013, a proposed regulatory return on equity of 11% and a 52% equity ratio. We view this fully regulated transmission company as a small but positive contributor to Capital Holdings' overall credit profile.

In 2011, NextEra Energy Resources completed the sale of four of its contracted natural gas-fired generating assets to an affiliate of LS Power for approximately $1.05 billion. The company also sold one of its merchant natural gas generating assets to Entergy Corporation for approximately $346 million. We viewed the sale of the contracted assets as modestly negative to overall credit quality in that it reduced the generation portfolio's diversity, as well as the percentage of contracted assets within the portfolio. The company's natural gas generating portfolio now consists predominantly of merchant generation in Texas, where it had only 67% of its 2012 gross margin and 47% of its 2013 gross margin hedged as of December 2011, by far the lowest of any of its generating assets. The sale also increased the proportion of energy trading and marketing, shale gas drilling, and retail energy marketing in the company's overall business mix compared to its more traditional, lower risk contracted generating assets, which we view as having a lower business risk profile.

- High, growing debt levels at both Capital Holdings and NextEra Energy Resources that is either guaranteed by NextEra Energy or has significant recourse characteristics

As NextEra Energy has emphasized the growth of its non-utility operations in recent years, debt levels at both Capital Holdings and NextEra Energy Resources have increased significantly and now together total $14.4 billion as of December 31, 2011 (on a Moody's adjusted basis), or 65% of the debt of the consolidated organization, up from $13.3 billion at year end 2010 and $11 billion at year end 2009. This considerable growth has diluted the value of the parent company guarantee of Capital Holdings debt over the years, as the parent now guarantees over $9 billion of the subsidiary's debt, including $1.2 billion of commercial paper outstanding as of January 31, 2012. Capital Holdings and Energy Resources have also provided credit and loan facilities of nearly $2 billion for construction loans and credit agreements related to the construction of its Genesis and Spanish solar projects, the Lone Star transmission lines, and some Canadian renewable generating assets, which are being drawn down as construction proceeds.

An additional $5.8 billion of debt is characterized as "limited recourse" debt under subsidiary NextEra Energy Resources on the company's financial statements. Though this debt may not be directly guaranteed, much of it is tied to NextEra Energy and/or Capital Holdings in some way, either through sponsorship of the underlying projects; tax interrelationships including guarantees of production tax credits on wind projects; cash traps at some projects that are tied to rating levels of NextEra Energy or Capital Holdings, or through financial covenants at NextEra Energy itself. As a result, we include this limited recourse debt in our analytical approach and in our published financial ratios.

At December 31, 2011, the long-term debt to capitalization of Capital Holdings, including all of the NextEra Energy Resources debt, was a high 77%. Despite receiving $1.2 billion of proceeds from the sale of the natural gas plants and nearly $500 million from tax equity transactions during 2011, little to none of these proceeds was used to pay down long-term debt or commercial paper in 2011, both of which increased over the course of the year. The parent did use part of the natural gas plant sale proceeds to repurchase approximately $375 million of its common shares.

We note that this debt resides at both Capital Holdings and Energy Resources, two major entities that do not file separate audited SEC financial statements, which are filed only on a consolidated basis at NextEra Energy, Inc. We believe the level of financial and operational transparency at Capital Holdings and Energy Resources has not increased commensurately with their business risk profiles over the last several years. In addition to the lack of audited financials, these companies do not file or otherwise disclose their bank credit facilities, financial covenant requirements, or the level of cushion they may have under such covenants.

- Consolidated cash flow coverage metrics are weak for a Baa1 rated hybrid power company, particularly as the company's non-utility operations have grown and diversified

As a hybrid power company with both unregulated generation and regulated utility operations, NextEra Energy is analyzed using guidelines in both Moody's Unregulated Power Companies and Moody's Regulated Electric and Gas Utilities rating methodologies. The company's consolidated financial performance and cash flow coverage metrics have historically been relatively stable and adequate for a company with a balanced mix of businesses, but have not strengthened as it has become more reliant on unregulated cash flows to service its growing debt obligations.

As the company has become more of a wholesale generating company, diversified into other energy related businesses, and expanded internationally, we would expect cash flow coverage metrics to strengthen to offset and mitigate the higher risk associated with the growth of these businesses. Over the last two years, the company has generated consolidated CFO pre-working capital interest coverage of 4.5x in 2010 and 4.8x in 2011, at the low end of the 3.6x to 6.9x rating range guidelines for a Baa rating under out Unregulated Power Companies rating methodology. In addition, the ratio of consolidated CFO pre-working capital to debt of 17.6% in 2010 and 18.9% in 2011 were both well below the Baa rating range of 21% to 35% under the methodology. We note that utility FPL's credit metrics remain well above the parameters outlined for its A2 Issuer Rating under our Regulated Utilities rating methodology, which offsets to some degree the consolidated company's weaker credit profile. The diverse and highly contracted nature of the generating portfolio also helps to mitigate risks associated with these low coverage ratios.

- Energy trading and marketing, shale gas well drilling, Texas retail, and Spanish solar businesses increase risk profile, although none are expected to grow from current levels

Over the last few years, NextEra Energy Resources has diversified away from being a predominantly domestic, asset focused wholesale power company with expansions into several non-asset based and international businesses. The company expanded its Houston based trading operations several years ago with the gross margin contribution from this business fluctuating widely and the company citing results from these activities as a more material driver of its overall financial performance beginning in 2008 and 2009. The contribution of the trading business over the last two years was lower because of lower power market volatility and unfavorable market conditions. In November 2011, the company announced that it was relocating its gas trading operations from Houston to its corporate headquarters in Florida and that it had lowered expectations for this business in 2012 and going forward. We view any movement away from energy trading and marketing as credit supportive for NextEra Energy and Capital Holdings.

During the third quarter of 2011, Gexa, the company's Texas retail electric provider, was negatively affected by extreme weather conditions, including over three weeks of record heat in the state. With the company's Texas wind assets negatively impacted by a low wind resource over the same period, Gexa was forced to purchase power to cover some of its hedges. The result was a small, but negative, impact on the entire organization's 2011 financial performance.

NextEra Energy Resources has also begun to invest in natural gas shale drilling projects, with capital expenditures in this sector expected to range between $400 to $600 million from 2010 through 2014. While this level of investment is modest compared to the company's $3.1 billion of total capital expenditures in 2011, we view shale gas drilling and related businesses as having a higher risk profile than the company's traditional wholesale generation business. We believe the involvement of one of the leading "clean energy" companies in what is currently one of the most environmentally controversial drilling practices, "fracking", even to a limited degree, entails reputational and other intangible risks.

The company does not expect to grow any of these businesses from their current levels and projects that the consolidated organization's overall business mix will shift to a more regulated and long-term contracted profile by 2014 due to renewed growth, capital spending, and rate relief at its Florida utility and initial contributions from Lone Star, its Texas regulated transmission company.

Liquidity Profile

Capital Holding's maintains $4.6 billion of bank revolving lines of credit supporting a liquidity profile that became increasingly constrained during 2011 by substantially higher levels of guarantees issued, higher commercial paper and letters of credit outstanding, significant credit related collateral calls, and an energy trading and marketing business that could suddenly require additional collateral.

At December 31, 2011, Capital Holdings and Energy Resources had $1.5 billion of standby letters of credit; $104 million of surety bonds; and a substantial $14.5 billion notional amount of guarantees outstanding, of which approximately $9.1 billion have expiration dates over the next five years. The company's notional amount of guarantees outstanding increased by over 50% during 2011 from $9.5 billion at December 31, 2010 as the company provided construction guarantees to several solar, wind and transmission projects during the year.

Approximately $1.3 billion of Capital Holdings' standby letters of credit outstanding at December 31, 2011 were issued under Capital Holdings' credit facilities which, when combined with its outstanding commercial paper, utilized over half of the company's $4.6 billion of bank revolving credit facilities. Commercial paper outstanding at Capital Holdings increased significantly during the second half of 2011 to $1.2 billion at January 31, 2012 from $395 million at June 30, 2011. Capital Holdings and Energy Resources have $1.8 billion of debt due in 2012, including approximately $1.1 billion of commercial paper and $700 million of long-term debt. Capital Holdings had $339 million of cash on hand as of December 31, 2011, up from $282 million at December 31, 2010.

NextEra Energy also has substantial exposure to potential collateral calls in the event of credit rating downgrades. If Capital Holdings or FPL's credit ratings were downgraded to BBB/Baa2, NextEra Energy would be required to post collateral of approximately $800 million ($250 million at FPL). If Capital Holdings' or FPL's credit ratings were downgraded below investment grade, the company would be required to post collateral of approximately $2.8 billion ($0.9 billion at FPL). This level of downgrade related collateral calls is well above industry peers such as Constellation Energy and Exelon Generation, whose collateral calls are $1.1 billion and $1.6 billion, respectively, if downgraded below investment grade (as of December 31, 2011). Moreover, additional NextEra Energy contracts that do not have rating triggers but require the maintenance of certain financial measures or have other credit-related cross default triggers could require additional collateral of up to approximately $600 million ($100 million at FPL).

Capital Holdings refinanced and extended a portion of its credit facilities in February 2012. Of its $4.6 billion of bank credit facilities, approximately $3.1 billion now expires in 2017, with approximately $1.5 billion currently expiring in 2013, which the company expects to refinance and extend early next year. Capital Holdings does not have a material adverse change clause in its bank credit facilities, although it is required to maintain a debt to capitalization covenant, which the company does not make public. The company reported that it was in compliance with this covenant at December 31, 2011.

Rating Outlook

The stable rating outlook reflects Moody's expectation that the growth of the company's unregulated generating portfolio will moderate beyond 2012 when production tax credits expire; that debt levels at Capital Holdings and Energy Resources will stabilize and not increase beyond current levels; that the company will maintain a high level of long-term contracts and hedges in place on its remaining wholesale generating assets; and that it will strictly limit its energy marketing and trading, shale gas drilling, Texas retail, and Spanish solar businesses to current levels.

What Could Change the Rating - Up

A higher rating could be considered if the company materially reduces debt levels at Capital Holdings and/or Energy Resources; reduces or eliminates any or all of its diversified businesses; improves its liquidity position by reducing the level of contingent collateral and other potential calls on liquidity; or if cash flow coverage metrics increase to levels more in line with our parameters for a high Baa rated unregulated power company, including consolidated CFO pre-working capital to debt of 30% or higher and CFO pre-working capital to interest of 6.0x or higher on a sustained basis.

What Could Change the Rating - Down

A downgrade could be considered if leverage continues to increase at Capital Holdings and/or Energy Resources; if there is any further expansion into diversified, higher risk businesses; if there is a significant energy trading loss; if liquidity at Capital Holdings tightens further from already constrained levels; or if consolidated cash flow coverage metrics remain weak for its current rating and risk profile, including CFO pre-working capital to debt below 20% or CFO pre-working capital interest coverage below 5.0x.

This credit rating is an opinion as to the creditworthiness of a debt obligation of the issuer, not on the equity securities of the issuer or any form of security that is available to retail investors. It would be dangerous for retail investors to make any investment decision based on this credit rating. If in doubt you should contact your financial or other professional adviser.

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Board #2 (UCT)
Attachment 5

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Major Rating Factors

Corporate Credit Rating

A-/Stable/--

Strengths:

- Excellent competitive position in liquids transportation and natural gas distribution
- Long-term, predictable cash flows

Weaknesses:

- High leverage

Rationale

The ratings on Alberta-based holding company Enbridge Inc. reflect Standard & Poor's Ratings Services' view of an "excellent" business risk profile, supported by the excellent competitive position of the company's liquids pipelines and gas distribution businesses and its long-term and predictable cash flow with limited commodity exposure. In our view, the "significant" financial risk profile, which reflects high leverage, offsets these strengths. We view management and governance to be "fair".

Enbridge has wholly and partially owned subsidiaries that focus primarily on owning and operating natural gas and oil pipelines in North America. The company's subsidiary, Enbridge Pipelines Inc. (EPI; A-/Stable/--), undertakes crude oil transportation, while subsidiary Enbridge Gas Distribution Inc. (EGD; A-/Stable/--) leads its gas distribution businesses. Liquids pipelines provide about 50% of the group's adjusted earnings, and Enbridge Gas and returns from other gas distribution assets and services represent 15%-20%. Sponsored investments, dominated by Enbridge Energy Partners L.P. (EEP; BBB/Negative/--), provide about 20% of earnings; gas pipelines, processing, and energy services make up the rest. Enbridge Inc. had C$21 billion in consolidated debt (Standard & Poor's-adjusted) as of Sept. 30, 2012.

In our opinion, the excellent competitive position of the liquids and natural gas distribution segments continues to support the company's excellent business risk profile. We base this on the lack of direct commodity price exposure, and stable volumes with high medium-term visibility based on either market fundamentals or take-or-pay commitments. In addition, the contractual profile typically features long-term contracts on favorable terms with creditworthy counterparties. The segment also benefits from considerable scale as the largest provider (by capacity) of crude transportation services out of the Western Canadian Sedimentary Basin.

We believe the gas distribution business' excellent competitive position reflects ongoing consistent and predictable regulation, commodity cost pass thru, and a demonstrated ability to earn the return on equity (ROE) the regulator establishes. The utilities operate as natural monopolies in their franchise areas and have limited bypass risk, further enhancing their competitive position.

We believe Enbridge will continue to generate long-term, predictable cash flow that will continue to support credit quality. The competitive position of the company's primary lines of business supports this. We believe cash flow growth will be stable as well, based on long-term contracts with relatively low risk. In our view, the contractual foundations underpinning investment are similar to the existing business and generally feature either long-term cost-of-service or take-or-pay contracts with limited direct commodity price risk and low levels of volume risk. Also supporting our view are stable financial policies, extensive hedging program that limit the effects of market movements in the medium-to-long term, and a track record of managing balance-sheet strength.

We expect Enbridge's consolidated credit metrics to remain weak for the ratings, with limited headroom over the 13% funds from operations (FFO)-to-debt floor we associate with the ratings. The large, ongoing capital program that could reach as much as C$35 billion from 2012-2016 will continue to pressure metrics because of the partial debt financing of new pipelines and cash flow that does not begin until projects are in service.

Liquidity

Our commercial paper rating on Enbridge is 'A-1'. We believe the company has adequate liquidity as per our criteria. Our assessment incorporates the following expectations and assumptions:

- We expect Enbridge's liquidity sources over uses to exceed 1.2x during the next 12 months, and we expect sources to exceed uses even in the unlikely event that EBITDA declines 15%.
- The company will continue to have solid relationships with its banks, a generally high standing in credit markets, and generally very prudent risk management.
- Consolidated liquidity sources include FFO of about C$3.5 billion in the next 12 months; about C$1.7 billion of unrestricted cash and cash equivalents as of Sept. 30, 2012; and undrawn committed facilities of more than C$8 billion.
- Uses of liquidity in the next 12 months include expected capital spending of C$7 billion-C$8 billion, and about C$2 billion in debt maturities and shareholder distributions.
- We expect Enbridge to be discretionary cash flow negative for the next several years as it continues its ongoing capital program.

We believe the company will continue complying with all of its myriad covenants.

Outlook

The stable outlook reflects our view that cash flow from both the existing businesses and new developments will remain very stable. We believe credit metrics, although weak for the ratings, will remain above established thresholds. A lowering of adjusted FFO-to-debt below 13% would likely result in a downgrade. Deterioration in the business risk or a failure to deliver the capital program on time and budget could also result in a lower rating. Without a material reduction in leverage, an upgrade during our two-year outlook horizon is unlikely.

Business Description

Enbridge is a large, diverse holding company. Its operations center largely on transporting crude oil south from Canada to the U.S. Midwest and, with the Seaway pipeline acquisition and reversal, to the Gulf Coast; transporting natural gas to the U.S. Midwest, Gulf Coast, and eastern Canada; and distributing natural gas in Ontario, Quebec, and

New Brunswick. The company retains a 22% ownership interest in EEP, a U.S. master limited partnership that transports liquid petroleum products and natural gas, and owns natural gas gathering, treatment, and processing operations in the U.S. Enbridge also holds an interest in Enbridge Income Fund (EIF; not rated), which partially owns Alliance Pipeline L.P. (senior secured debt rating: BBB+/Stable). Enbridge also owns 100% of Enbridge Energy L.P. (EELP; not rated) through which it funds 67% of the Alberta Clipper pipeline's equity. It manages EEP, EIF, and EELP's day-to-day operations and strategic direction.

Enbridge is a publicly traded company. There are four primary business units: liquids pipelines, which Enbridge Pipelines dominates; natural gas delivery and services, which Enbridge Gas dominates; gas pipelines, processing and energy services, which themselves include the company's Gulf of Mexico offshore assets and interests in the Alliance and Vector pipelines; and sponsored investments, specifically EEP, EIF, and EELP. The company also has a corporate segment.

Rating Methodology

The ratings on Enbridge and its subsidiaries reflect Standard & Poor's consolidated rating methodology. The ratings also reflect our view of a consolidated business risk profile that captures the business risk and cash flow of the company's various subsidiaries, including its regulated operations. The methodology is appropriate given the intercompany investments between Enbridge and its wholly owned subsidiaries, Enbridge Pipelines and Enbridge Gas. As a result, the corporate credit ratings on these subsidiaries are the same as those on the parent.

Enbridge issues debt at its subsidiaries as well as directly at the holding company level. It does not typically guarantee its subsidiaries' debt. We do not structurally subordinate the debt at Enbridge because we view that substantial diversity of subsidiary holdings available to service the debt at the holding company as offsetting the structural subordination and a number of investments are being made directly at the holding company level. We do, however, rate Enbridge's preferred stock two notches lower, at 'BBB', to reflect its weaker claim to debt in bankruptcy.

Intercorporate financial links remain what we view as strong. At Sept. 30, 2012, EPI had more than C$4 billion of loans to and from affiliates on a consolidated asset base of about C$24 billion. EGD had about C$1.2 billion of loans from and investments in affiliates on an asset base of about C$7.7 billion.

Excellent Business Risk Profile

Liquids pipelines (about 50% of earnings)

Enbridge System. The system's excellent competitive position supports the excellent competitive position of both the liquids segment and the company, in our view. Its contractual profile, relatively low levels of medium-term volume risk, lack of direct commodity price exposure, and large scale support our assessment. The Enbridge System consists of the Canadian portion of the mainline system that transports oil from Alberta to the U.S. and eastern Canada. The system has a capacity of about 2 million barrels per day (mbpd) and is currently and forecast to be the leading transporter of crude oil out of Alberta. The system's product is the largest source of crude oil to the world's largest market, the U.S. The oil sands in Alberta have long reserve lives with steady expected volume growth. The reserves in Alberta rank third globally by volume.

The Enbridge system operates under a 10-year competitive tolling settlement (CTS) that transfers some risk to Enbridge while providing the company with the opportunity to earn higher returns. In exchange, the CTS provides shippers with greater transparency and stability in tolls for the duration of the CTS, which expires June 20, 2021. Canada's National Energy Board (NEB) formally regulates the system. However, since 1995, the system has operated under a series of negotiated agreements. If no agreement can be reached, rates are established under a cost-of-service methodology.

The key risk from the CTS is volume. Due to the long lead times and challenges associated with competing pipelines, the stable and transparent production growth profile (for more information, see "Canadian Oil Pipeline Companies' Expansion Projects Shouldn't Dent Their Credit Quality Despite Their Cost," published Oct. 16, 2012, on RatingsDirect on the Global Credit Portal), downstream contracts that pull volumes through the mainline, and the volume off ramp in the CTS, we believe the probability of an unexpected long-term, material volume decline is low.

Threshold volumes, which we believe provide some downside volume protection, are 1.25 mbpd until Dec. 31, 2014, and step up to 1.35 mbpd for the contract's remainder. However, as volumes increase, as a result of capital investments to expand capacity, the thresholds will provide less downside protection. The time lag associated with thresholds minimizes some of the protection they provide, although we do not expect Enbridge to reach the thresholds. Thresholds are measured based on a rolling nine-month measurement period, followed by a 10-day notice and a minimum 90 day negotiating period. At the end of this, if no agreement has been reached, the company could apply to the NEB for relief through a return to cost-of-service. Threshold volumes also have carve-outs dealing with Bakken volumes and system availability.

Other risks the company faces include operating costs, integrity spending, and market. A combination of off-ramps in the CTS or (where possible) market hedges mitigate material downside risk. Other off-ramps cover regulatory changes that affect operating and integrity costs. Key hedges include foreign exchange, interest rates, and power (where possible). Tolls on the CTS increase at a rate of 75% of Canadian GDPP.

A key feature of the CTS is that shippers may renegotiate the settlement Jan. 1, 2013, if the Keystone XL pipeline has not received a U.S. presidential permit. The shippers have one month to provide notice of renegotiation. Given that the CTS was negotiated under the assumption that Keystone XL would proceed, if volumes appear destined to be moved on the Enbridge system instead of Keystone XL for any meaningful amount of time, shippers might seek to renegotiate. Should this happen, we would not expect any outcome to negatively affect Enbridge any more than the impact of Keystone XL proceeding.

Regional oil sands. Long-term contracts with minimum volume commitments and increasing volumes in the basin support our expectation of stable cash flow from this segment. The system consists of laterals to connect projects to two primary pipeline systems and related facilities and terminals in Edmonton and Hardisty, Alta. Laterals are typically take-or-pay contracts based on cost-of-service tolls, providing highly stable cash flow. The Athabasca and Waupisoo pipelines have long-term take-or-pay contracts providing a base level ROE, with increased volumes providing some upside and low levels of operating cost exposure. Returns could fall below expectations if operating costs exceed levels assumed in the agreement or if volumes decline.

Southern Lights. Southern Lights' long-term take-or-pay contracts are based on a cost-of-service tolling methodology and a stand-alone rate base is expected to continue to provide stable cash flow. It is a 180,000 bpd diluent pipeline from Chicago to Edmonton.

Other pipelines. Collectively, these are relatively small. However, we expect the Spearhead and Seaway pipelines to experience substantial cash flow growth as a result of large capital programs.

Gas distribution (15%-20% of earnings)

Factors contributing to Enbridge Gas' excellent business risk profile are the relatively stable customer growth rates in the company's service territory. EGD is the largest natural gas distributor in Canada, serving about 2 million customers in central and eastern Ontario. Offsetting this somewhat is its exposure to weather-induced variability in gas demand and related cash flows. We expect the majority of the company's capital program of about C$2.5 billion from 2012-2016 to go into the rate base.

Gas pipelines, processing, and energy services (10%-15% of earnings)

The segment has more risk than others because it has a mixture of commodity, volume, and recontracting risk. However, new investments in Enbridge Offshore (a system of natural gas gathering and transmission lines in the Gulf of Mexico) and Canadian midstream are underpinned by contracts that we expect to improve the segment's business risk profile.

Enbridge Offshore earnings are volume-sensitive and subject to fluctuations in producer drilling programs and weather dependent. Contracts are typically life of lease commitments. Growth projects differ in that they contain minimum returns established through take or pay provisions.

The Alliance Pipeline has firm shipping contracts that underpin steady and predictable earnings. However, the current shipping contracts expire in 2015, exposing this segment to recontracting risk. The Alliance Pipeline U.S. connects gas production in western Canada with markets in the Midwestern and Northeastern U.S.

The Vector pipeline also benefits from shipping contracts for about 90% of its capacity through 2015. However, as with Alliance, the contracts could expire that year or suffer from less favorable renewals. The Vector pipeline runs between Chicago and a major storage facility in Dawn, Ont.

Aux Sable has a contract with BP Products North America Inc. for its natural gas liquids (NGL) production. BP pays Aux Sable a fixed fee and a share of profits above a certain level, and reimburses Aux Sable for all operating, maintenance, and capital costs (subject to some limits on capital costs). The agreement, which greatly reduces downside risk to the company, extends to at least 2026 (although BP has the right to cancel the agreement if losses exceed a certain level). Enbridge has a 43% interest in Aux Sable, a NGL extraction facility that the Alliance Pipeline near Chicago feeds.

Energy Services provides marketing services to Enbridge's customers. Earnings can be quite volatile and are of limited credit support accordingly.

Sponsored investments (about 20% of earnings)

EEP is a U.S.-based limited partnership that owns and operates crude oil pipelines and natural gas gathering and processing facilities. The company operates the Lakehead system, which is integrated with the Enbridge System at the

Canada-U.S. border. Enbridge is the general partner and has a 22% interest in EEP. In our view, EEP has a strong business risk profile and aggressive financial risk profile.

Some of the company's earnings are subject to volume and commodity price risk. However, as with the Enbridge System, the Lakehead system operates under the CTS but has priority in receiving tolls under the system. Natural gas volumes are somewhat more uncertain.

Enbridge Income Fund. Enbridge has been using EIF as a means of issuing equity by selling assets to EIF, which in turn issues trust units. Enbridge has not always fully participated unit issuance, resulting in some mild deterioration in its ownership percentage. The most recent dropdown announced in October 2012 is for C$1.2 billion of renewable assets and contracted crude oil storage at Hardisty. Additional performance incentives enable Enbridge to earn additional income over and above ownership and equity share. Primary assets include 50% interest in Alliance Pipeline Canada, 100% of Enbridge Saskatchewan (both acquired from Enbridge in 2003), and a portfolio of 400 megawatts of renewable and alternative energy.

EIF has a weaker business risk profile in part because of the concentration of renewable assets which have more volume risk.

Aggressive growth profile

Enbridge consistently has a large capital program, although we believe a track record of executing large projects on time and on budget reduces execution risk. In addition, the company has a mix of capital cost exposures throughout its capital program, and given the size of its small capital, cost overruns could have a relatively small effect on credit metrics. Although we don't expect it, if Enbridge fails to execute on its capital program, a negative rating action could follow.

We believe the capital program is consistent with the company's previous track record of investing in assets characterized by long-term, commercially secured contracts on favorable terms , that we expect to generate stable cash flow, supporting credit quality. In total, we believe that the capital program will reduce Enbridge's already low exposure to commodity price risk. The capital program could reach as much as C$35 billion from 2012-2016, with about C$30 billion secured, about C$2 billion highly probable, and the remainder risk adjusted. Any delays in capital spending could reduce near-term pressure on credit metrics.

The capital program focuses on expanding the liquids system's capacity and reach, and we believe that the company will spend more than two-thirds of the program in this segment. Growth capital focuses on expanding the regional oil pipelines system, expanding the Enbridge and Lakehead systems, increasing access to eastern refineries, expanding services to Bakken, and increasing reach to the Gulf Coast. Part of the strategy is to pull volumes through the common carrier mainline by securing downstream contracts with minimum take-or-pay provisions.

Profitability

The profit base is quite solid, in our opinion, because most earnings are either relatively low-risk, long-term contracts or are directly regulated cost-of-service entities. The business has a relatively high degree of transparency regarding future earnings and we expect growth projects to continue to expand the stable base for earnings. Enbridge also benefits from its size and diversity of contracts and segments (which reduces the effect of operational issues and most contract renewals). Fluctuations in the hedging program might affect earnings, and margins are exposed to changes in commodity prices that are either passed through or on which the company earns a fixed margin.

Financial Policy

Enbridge's targeted financial parameters reflect a significant financial risk profile but a moderate approach to financial risk management, in our view. The parameters articulate some of management's risk tolerances include:

- Adjusted reported debt capitalization of 60%-65%, excluding the nonrecourse debt of EIF and Alliance Pipeline;
- Floating-rate debt of less than 25% of total term debt;
- Maximum annual term debt maturities of less than 15% of total term debt;
- A common dividend payout of 60%-75%; and
- An earnings-at-risk target of less than 5%.

The policy to limit near term earnings at risk exposed to market prices results in the company hedging about many market risks, including interest rates, foreign exchange, and commodity price risks, among others.

We believe that the company also has an extensive hedging program to limit the effects of interest rate, foreign exchange, power price movements, and other risk in the medium-to-long term. The program limits the cash flow impacts of these variables and increases the long-term stability of cash flow. Power price hedges are important, in our view, given the fixed fee structure underpinning some of its liquids contracts that expose the company to fluctuations in power prices, a key operating cost.

We expect Enbridge to manage its balance sheet and credit metrics in part through issuing preferred shares, asset dropdowns to its sponsored investments, reducing its ownership stake in its sponsored investments, and equity issuance. This would be consistent with recent actions that support credit quality during the capital program.

Significant Financial Risk Profile

Accounting

Enbridge started reporting under U.S. generally accepted accounting principles (GAAP) Jan. 1, 2012. U.S. GAAP fully consolidates EEP as a result of the principles' definitions of control. Previously, under Canadian GAAP, EEP was an equity investment.

To better reflect Enbridge's assumed financial risk, Standard & Poor's makes an offsetting adjustment to its total debt outstanding for the amounts relating to purchased gas-in-storage at EGD. The company's commercial paper program finances gas-in-storage amounts, and, as such, reports it as part of short-term debt. Given our expectation of full commodity cost recovery under the Ontario Energy Board's provisions and to eliminate the seasonality, we remove the amounts from short-term debt and total assets (see table 1).

Table 1

Reconciliation Of Enbridge Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$)

	--Fiscal year ended Dec. 31, 2011--									
Enbridge Inc. reported amounts	**Debt**	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	16,232.0	8,841.0	19,402.0	2,828.0	1,891.0	711.0	2,625.0	2,625.0	537.0	2,681.0
Standard & Poor's adjustments										
Intermediate hybrids reported as equity	528.0	(528.0)	N/A	N/A	N/A	6.5	(6.5)	(6.5)	(6.5)	N/A
Postretirement benefit obligations	370.8	(511.1)	N/A	(4.0)	(4.0)	N/A	21.1	21.1	N/A	N/A
Capitalized interest	N/A	N/A	N/A	N/A	N/A	61.0	(61.0)	(61.0)	N/A	(61.0)
Share-based compensation expense	N/A	N/A	N/A	18.0	N/A	N/A	N/A	N/A	N/A	N/A
Reclassification of nonoperating income (expenses)	N/A	N/A	N/A	N/A	448.0	N/A	N/A	N/A	N/A	N/A
Reclassification of working-capital cash flow changes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	(251.0)	N/A	N/A
Minority interests	N/A	846.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Debt--other	(380.0)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total adjustments	518.8	(193.1)	0.0	14.0	444.0	67.5	(46.4)	(297.4)	(6.5)	(61.0)
Standard & Poor's adjusted amounts	**Debt**	**Equity**	**Revenues**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**	**Dividends paid**	**Capital expenditures**
Adjusted	16,750.8	8,647.9	19,402.0	2,842.0	2,335.0	778.5	2,578.6	2,327.6	530.5	2,620.0

N/A--Not applicable.

Cash-flow adequacy

Given the capital program, we expect credit metrics to remain weak, with limited headroom above the minimum 13% consolidated adjusted FFO-to-debt threshold we associate with the rating. We forecast credit metrics will be weakest in 2013, although headroom above thresholds might improve in the next several years as projects are completed and begin to generate cash flow. We believe the capital program is front-end-loaded and could reach as much as C$16 billion in 2013-2014. We forecast adjusted leverage within management's 60%-65% target, although we expect it might be closer to the high end of the range. We believe Enbridge will remain free operating cash-flow negative for the next several years as a result of the large capital program.

In addition to regular debt issuance, we have assumed management will continue to finance its capital program through ongoing preferred share issuance, equity issuance, and asset dropdowns, all of which support credit quality. We also believe the company has other levers, including selling some of its positions in its sponsored investments, that it could use to raise cash to fund its growth program if required.

Table 2

Enbridge Inc.--Peer Comparison

Industry Sector: Gas

	--Three-year average results--						
	Enbridge Inc.	**Enbridge Pipelines Inc.**	**TransCanada PipeLines Ltd.**	**Fortis Inc.**	**Pembina Pipeline Corp.**	**Kinder Morgan Energy Partners L.P.**	**Colonial Pipeline Co.**
Rating as of Dec. 24, 2012	A-/Stable/--	A-/Stable/--	A-/Stable/A-2	A-/Stable/--	BBB/Stable/--	BBB/Stable/A-2	A/Stable/A-1
Currency (mil.)	C$					US$	
Revenues	15,665.0	1,286.7	8,723.0	3,682.7	1,240.2	7,764.1	992.7
EBITDA	2,433.0	770.0	4,626.5	1,162.0	321.0	3,073.1	592.2
Net income from continuing operations	1,178.7	608.3	1,387.0	330.3	167.9	1,280.5	292.5
Funds from operations (FFO)	2,024.8	780.9	3,143.6	715.0	268.0	2,485.2	371.4
Capital expenditures	2,728.3	1,641.3	4,452.3	978.6	280.9	1,211.7	52.5
Dividends paid	470.5	658.7	1,212.2	189.3	248.1	1,947.4	297.8
Debt	15,227.7	6,524.6	24,648.6	6,818.5	1,586.7	12,782.3	1,370.2
Preferred stock	217.7	0.0	699.5	415.2	0.0	0.0	0.0
Equity	8,121.0	5,167.5	17,210.1	3,835.0	1,027.5	7,206.8	(247.1)
Debt and equity	23,348.7	11,692.1	41,858.7	10,653.5	2,614.3	19,989.1	1,123.1
Adjusted ratios							
EBITDA margin (%)	15.5	59.8	53.0	31.6	25.9	39.6	59.7
EBIT interest coverage (x)	2.9	2.9	2.0	1.9	3.3	4.3	6.5
FFO interest coverage (x)	3.7	3.2	3.0	2.7	4.4	5.7	5.3
FFO/debt (%)	13.3	12.0	12.8	10.5	16.9	19.4	27.1
Discretionary cash flow/debt (%)	(7.3)	(22.2)	(10.3)	(6.4)	(17.1)	(5.7)	2.0
Net cash flow/capex (%)	57.0	7.4	43.4	53.7	7.1	44.4	140.5
Total debt/debt plus equity (%)	65.2	55.8	58.9	64.0	60.7	63.9	122.0
Return on capital (%)	8.6	8.2	7.2	7.1	9.8	11.3	38.8
Return on common equity (%)	14.1	10.7	6.3	8.1	15.7	18.2	(142.5)

Table 2

Enbridge Inc.--Peer Comparison (cont.)							
Common dividend payout ratio (unadjusted; %)	55.9	108.3	80.6	67.3	148.7	152.1	101.8

Table 3

Enbridge Inc.--Financial Summary

Industry Sector: Gas

	--Fiscal year ended Dec. 31--				
(Mil. C$)	**2011**	**2010**	**2009**	**2008**	**2007**
Rating history	A-/Stable/--	A-/Stable/--	A-/Stable/--	A-/Stable/--	A-/Stable/--
Revenues	19,402.0	15,127.0	12,466.0	16,131.3	11,919.4
EBITDA	2,842.0	2,410.0	2,047.0	2,034.4	1,751.1
Net income from continuing operations	1,004.0	970.0	1,562.0	1,327.7	707.1
Funds from operations (FFO)	2,327.6	2,075.8	1,671.0	1,316.2	1,305.7
Capital expenditures	2,620.0	2,341.0	3,224.0	3,554.7	2,238.0
Dividends paid	530.5	430.5	450.5	362.7	455.8
Debt	16,750.8	15,011.3	13,921.2	12,674.6	9,956.0
Preferred stock	528.0	62.5	62.5	62.5	62.5
Equity	8,647.9	7,921.6	7,793.5	7,218.1	5,827.0
Debt and equity	25,398.7	22,932.9	21,714.6	19,892.7	15,783.0
Adjusted ratios					
EBITDA margin (%)	14.6	15.9	16.4	12.6	14.7
EBIT interest coverage (x)	3.0	2.5	3.0	2.7	2.4
FFO interest coverage (x)	4.0	3.7	3.3	3.0	3.1
FFO/debt (%)	13.9	13.8	12.0	10.4	13.1
Discretionary cash flow/debt (%)	(3.4)	(6.6)	(12.7)	(20.6)	(13.7)
Net cash flow/capex (%)	68.6	70.3	37.9	26.8	38.0
Debt/debt and equity (%)	66.0	65.5	64.1	63.7	63.1
Return on capital (%)	8.7	7.8	9.4	9.1	9.2
Return on common equity (%)	12.2	11.2	19.4	20.3	12.9
Common dividend payout ratio (unadjusted; %)	76.6	67.3	35.7	37.0	64.6

Related Criteria And Research

- Methodology: Business Risk/Financial Risk Matrix Expanded, Sept. 18, 2012
- Key Credit Factors: Criteria For Rating The Global Midstream Energy Industry, April 18, 2012
- Criteria Methodology: Differentiating The Issuer Credit Ratings Of A Regulated Utility Subsidiary And Its Parent, March 11, 2010
- Hybrid Capital Handbook: September 2008 Edition, Sept. 15, 2008
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008
- 2008 Corporate Criteria: Ratios And Adjustments, April 15, 2008

- 2008 Corporate Criteria: Commercial Paper, April 15, 2008

Ratings Detail (As Of December 24, 2012)	
Enbridge Inc.	
Corporate Credit Rating	A-/Stable/--
Commercial Paper	
Canadian CP Rating Scale	A-1(LOW)
Preferred Stock *Canadian Preferred Stock Rating Scale*	P-2
Preferred Stock	BBB
Senior Unsecured	A-
Corporate Credit Ratings History	
06-Dec-2011	A-/Stable/--
23-Mar-2011	A-/Negative/--
25-Nov-2003	A-/Stable/--
Business Risk Profile	Strong
Financial Risk Profile	Significant
Related Entities	
Enbridge Gas Distribution Inc.	
Issuer Credit Rating	A-/Stable/--
Preference Stock *Canadian Preferred Stock Rating Scale*	P-2
Preference Stock	BBB
Senior Unsecured	A-

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

Filed: 2013-03-28
EB-2011-0140
Board #2 (UCT)
Attachment 6

Rating Report

Report Date:
December 5, 2012

Previous Report:
December 6, 2011

DBRS
Insight beyond the rating.

Enbridge Inc.

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The Company

Enbridge Inc. is a diversified energy services company with operations in the following segments: Liquids Pipelines (53% of segment earnings in the 12-month period ending September 30, 2012), Sponsored Investments (23%), Gas Distribution (11%) and Gas Pipelines, Processing and Energy Services (13%).

Commercial Paper Limit

$2.5 billion

Recent Actions

November 30, 2012
New MTN issue

November 27, 2012
Preferred share issue

September 14, 2012
Assigned Issuer Rating

September 6, 2012
Preferred share issue

August 22, 2012
New MTN issue

July 18, 2012
Preferred share issue

May 11, 2012
Preferred share issue

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A (low)	Confirmed	Stable
Medium-Term Notes & Unsecured Debentures	A (low)	Confirmed	Stable
Cumulative Redeemable Preferred Shares	Pfd-2 (low)	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

DBRS has confirmed the Issuer Rating at A (low) and the ratings on the Medium-Term Notes & Unsecured Debentures, Commercial Paper and Cumulative Redeemable Preferred Shares ratings of Enbridge Inc. (ENB or the Company) at A (low), R-1 (low) and Pfd-2 (low), respectively, all with Stable trends. The ratings reflect (1) a relatively strong business risk profile, (2) pressure on the Company's near-to-medium-term credit metrics and (3) results under the 10-year Competitive Tolling Settlement (CTS) effective July 1, 2011.

(1) ENB's low-risk, mostly regulated operations provide roughly 85% to 90% of its earnings. ENB derived about one-quarter of its segment earnings for the last 12 months (LTM) ending September 30, 2012, from entities with no external debt. The remaining three-quarters of segment earnings were derived mostly from entities with low-risk, mostly regulated operations that generate stable earnings, including Enbridge Pipelines Inc. (EPI), Enbridge Gas Distribution Inc. (EGD), Enbridge Income Fund (EIF) and Enbridge Energy Partners, L.P. (EEP, 21.8% owned by ENB), accounting for a combined 60% of segment earnings.

(2) DBRS expects ENB's credit metrics to be pressured during the early years of its planned $32.1 billion capex program from 2012 to 2016, due to a significant debt financing component related to large free cash flow deficits. However, DBRS expects that any such potential weakness would be shallower than experienced in 2008-2009, as a result of the shorter average construction period and lower average construction costs for the current portfolio of projects, which are relatively well spread out in terms of expected completion.

(3) The CTS provides for a joint tariff for volumes shipped on both the Canadian (Enbridge System or Mainline) and U.S. (Lakehead) portions of the Enbridge/Lakehead crude oil pipeline system. Under the International Joint Tariff (IJT) agreement, any shortfall in toll revenues (e.g., as a result of lower throughput) under the CTS for Lakehead could potentially reduce the toll revenues available to Mainline. While Mainline earnings have benefited to date from the CTS provisions, the Mainline assumed increased business risk to EPI, compared with the previous cost-of-service agreements.

Rating Considerations

Strengths

(1) Low-cost crude oil pipeline from Western Canada
(2) Strong gas distribution franchise in Ontario
(3) Regulated and low-risk, diversified operations provide stable income from a strong asset base
(4) Large number of expansion projects support relatively low-risk earnings and cash flow growth potential

Challenges

(1) Large growth capex pressures credit metrics
(2) Moderately higher business risk of CTS tolling agreement and new business activities
(3) Competitive pressures from other pipelines
(4) Enbridge Gas Distribution earnings subject to volume risk and low return on equity (ROE)

Financial Information

	US GAAP	US GAAP	US GAAP	US GAAP	Cdn GAAP	Cdn GAAP	Cdn GAAP
Enbridge Inc.	9 mos. ended Sept. 30		12 mos. ended	For the year ended December 31			
(CAD millions where applicable)	2012	2011	Sept. 30, 2012	2011	2011	2010	2009
Net income before extras	966	845	1,235	1,114	1,124	979	879
Cash flow (bef. working capital changes)	2,302	2,037	2,920	2,655	2,374	2,114	1,774
Total debt in capital structure	57.6%	61.7%	57.6%	60.3%	59.4%	63.2%	63.4%
Cash flow/total debt	14.1%	14.1%	13.4%	13.1%	14.6%	13.8%	12.4%
EBIT interest coverage (times)	2.69	2.72	2.81	2.83	2.93	2.42	2.14
Fixed-charges coverage (times)	2.39	2.69	2.54	2.78	2.89	2.38	2.11

Rating Considerations Details

Strengths

(1) ENB indirectly owns and operates the Enbridge System (through EPI) and Lakehead Pipe Line System (through EEP), the largest low-cost crude oil pipeline system from the Western Canadian Sedimentary Basin (WCSB) to major Canadian and PADD II markets (Enbridge/Lakehead System). The Enbridge/Lakehead System has consistently provided the most economic route for WCSB producers shipping crude oil to PADD II/Chicago and currently provides almost two-thirds of Canadian export capacity. Given favourable market conditions (see below), PADD II is likely to remain a preferred market (generating one of the highest netbacks) for WCSB producers compared with the U.S. Gulf Coast (PADD III), U.S. Rocky Mountains (PADD IV) or the U.S. Pacific Northwest (PADD V).

Long-term supply/demand trends support the importance of WCSB crude oil shipments into PADD II, ensuring a long life of supply for the pipeline. WCSB crude oil production is expected to grow over the medium to long term, driven by large oil sands projects and expansions. Increases in conventional heavy oil and bitumen are expected to be complemented by light crude oil production growth. In addition, the Lakehead and North Dakota systems are well-positioned to receive production from the Bakken shale deposit in North Dakota, which has increased domestic light crude oil production in PADD II in recent years. Enbridge also benefits from this trend through its ownership of several crude oil feeder pipelines, including Athabasca System and Waupisoo Pipeline, as well as the Southern Lights and Spearhead pipelines.

(2) The Company benefits from ownership of EGD, the largest regulated natural gas utility in Canada, serving approximately two million customers in the central, eastern and Niagara Peninsula regions of Ontario. EGD's operations generate relatively low-risk, stable earnings. EGD is currently subject to a five-year Incentive Regulation (IR) plan that runs from 2008 to 2012 (see Regulation for more details).

(3) ENB's low-risk, mostly regulated operations, comprising a diversified portfolio of investments, provide approximately 85% to 90% of the Company's earnings. On a non-consolidated basis, ENB receives cash dividends from a variety of sources, supporting its ability to meet its direct debt obligations. Approximately one-quarter of ENB's segment earnings for LTM September 30, 2012, was derived from entities with no external debt, providing a stream of unencumbered dividends to the Company. The remaining three-quarters of segment earnings were derived mostly from entities with low-risk, mostly regulated operations generating stable earnings. These include EPI, EGD, EIF and EEP (accounting for a combined 60% of segment earnings), also providing a steady stream of dividends to ENB.

(4) The Company's $20 billion of commercially secured projects, a component of the $35 billion of enterprise wide growth capex investment opportunities identified by ENB for 2012 to 2016, support relatively low-risk earnings and cash flow growth potential over the near to medium term (see Major Growth Projects). During Q4 2012, ENB reached agreements for, among others: (a) transfer of certain crude oil storage and renewable generation assets to EIF for $1.164 billion and (b) the $1.8 billion Canadian Mainline Expansion from Edmonton to Hardisty. The Company is developing additional liquids pipeline projects, including intra-Alberta (e.g., Woodland Pipeline Extension), new markets extensions (e.g., Northern Gateway Pipeline), Bakken regional projects (e.g., Sandpiper Pipeline), and natural gas pipeline projects (e.g., Heidelberg Lateral Pipeline and Nexus Gas Transmission Project), providing a large portfolio of opportunities for future growth.

Challenges

(1) ENB has planned capex of $32.1 billion from 2012 to 2016 ($3.8 billion was spent during 9M 2012) as of early October 2012, likely resulting in significant free cash flow deficits (see Consolidated Financial Profile for details). Consequently, DBRS believes that the current capex plans, combined with the Company's plan to fund a significant portion of cash flow deficits with debt, could have a negative impact on the Company's credit metrics during the early years of the current plan, prior to improvement in the later years (as the longer-dated projects come onstream and begin to generate cash flow). However, DBRS expects that any such potential weakness would be shallower than experienced in the 2008-2009 period, as a result of the shorter average construction period and lower average construction costs for the current portfolio of projects, which are relatively well spread out, in terms of expected dates of completion and intial earnings contributions.

(2) (a) The CTS introduced volume and operational risks to the Mainline (which accounted for one-third of ENB's earnings in LTM September 30, 2012) through a fixed-toll methodology, instead of the cost-of-service basis used for the previous tolling arrangements. Although mitigated by certain minimum volume thresholds, the CTS could result in lower earnings and cash flow for EPI in the event of material disruption in service availability on the Mainline or the loss of significant volumes to alternative pipelines resulting from lower-than-expected end-user demand. While Mainline earnings benefited from the provisions of the CTS in LTM September 30, 2012, the CTS nevertheless resulted in increased business risk to EPI, compared with previous agreements, under which Mainline tolls would increase to compensate for reduced throughput. (b) DBRS expects the Company's business risk profile to remain relatively strong following completion of the current major project portfolio, as a result of the high weighting of capex toward low-risk liquids pipelines projects (approximately 70%) and natural gas pipelines and processing projects (approximately 15%). However, DBRS views the renewable energy projects, which are subject to volume risk and operations and maintenance (O&M) cost increase exposure (following expiry of initial fixed-price O&M contracts), and the new business activities (including Montana-Alberta Tie-Line (MATL) and Cabin Gas Plant (Cabin)) as having moderately higher business risk, although the latter is partly mitigated by long-term contractual arrangements.

(3) The Enbridge/Lakehead System is subject to competitive pressures from other pipelines originating in the WCSB and from alternative supply pipelines into the areas it serves. According to a June 2012 study by the Canadian Association of Petroleum Producers (CAPP), total capacity of major crude oil pipelines exiting the WCSB increased from 2.445 million b/d at year-end 2009 to 3.486 million b/d at year-end 2011. Key competitors include the following:

(a) (i) Phase 1 of TransCanada PipeLines Limited's (TCPL) Keystone Pipeline (Base Keystone), which extends from Hardisty, Alberta, to Wood River and Patoka, Illinois, had an initial nominal capacity of 435,000 b/d and was placed into commercial service on June 30, 2010. (ii) Phase 2 of Base Keystone, which expanded nominal capacity to 591,000 b/d and extended the pipeline to Cushing, Oklahoma, was placed in commercial service in Q1 2011. (iii) The Keystone XL Pipeline Project, which extends from Hardisty to Steele City, Nebraska, is designed to provide 830,000 b/d of nominal capacity and is expected to be placed into commercial service in 2015, provided U.S. regulatory approvals are obtained. The Gulf Coast Pipeline Project, from Cushing, Oklahoma, to Port Arthur, Texas, which will have an initial nominal capacity of 700,000 b/d, is expected to be operational in mid-to-late 2013. The combined system would have an initial capacity of 1.4 million b/d.

(b) Express Pipeline (Express) owns and operates a 280,000 b/d capacity pipeline from the WCSB to PADD IV. Express is connected to the 150,000 b/d capacity Platte Pipeline (Platte), serving the Patoka and Wood River market in PADD II. While representing competition, Express and Platte have much lower throughput capacity than the Enbridge/Lakehead System.

(c) An affiliate of Kinder Morgan Canada Inc. owns Trans Mountain Pipeline, a liquids pipeline with a current capacity of 300,000 b/d from Edmonton to Canada's west coast, serving refineries in Vancouver and Washington State. While representing competition, Trans Mountain Pipeline has much lower throughput capacity than the Enbridge/Lakehead System.

(4) Earnings from EGD (8% of ENB's segment income in LTM September 30, 2012) are exposed to volume risk, which is in turn sensitive to changes in weather, economic conditions and natural gas prices. Weather sensitivity is largely related to the winter heating season, with warmer (colder) than normal temperatures adversely (positively) affecting residential and commercial demand for natural gas and, therefore, financial measures at EGD. In addition, the IR plan set a low base level for allowed ROE at 8.39% through year-end 2012. Although EGD has the opportunity to earn higher returns, the upside is capped as described in the Regulation section of this report.

Enbridge Inc.

Report Date:
December 5, 2012

Earnings and Outlook

- ENB’s conversion to U.S. Generally Accepted Accounting Principles (GAAP) from Canadian GAAP resulted in minimal impact on net income before extras (DBRS adjusted) in 2011.

							Enbridge Inc.		**Segment Analysis**			
	US GAAP		**US GAAP**		**US GAAP**		**US GAAP**		**Cdn. GAAP**		**Cdn. GAAP**	
Enbridge Inc. (CAD millions)	9 mos. ended Sept. 30				12 mos. ended		For the year ended December 31					
Liquids Pipelines	2012		2011		Sept. 30, 2012		2011		2011		2010	
Canadian Mainline	315	35%	264	31%	387	33%	336	30%	337	30%	326	33%
Regional Oil Sands System	81	9%	81	10%	108	9%	108	10%	107	9%	68	7%
Southern Lights Pipeline	53	6%	54	6%	74	6%	75	7%	75	7%	82	8%
Spearhead Pipeline	30	3%	14	2%	33	3%	17	2%	17	2%	29	3%
Seaway Pipeline	13	1%	0	0%	13	1%	0	0%	0	0%	0	0%
U.S. Feeder Pipelines and Other	9	1%	(3)	0%	12	1%	0	0%	0	0%	7	1%
Subtotal (Liquids Pipelines)	**501**	55%	**410**	49%	**627**	53%	**536**	48%	**536**	48%	**512**	51%
Sponsored Investments												
Enbridge Energy Partners (21.8%)	109	12%	106	13%	154	13%	151	14%	152	13%	122	12%
Alberta Clipper U.S. (66.7%)	32	4%	32	4%	42	4%	42	4%	42	4%	42	4%
Enbridge Income Fund (35.4%)	55	6%	32	4%	74	6%	51	5%	59	5%	45	5%
Subtotal (Sponsored Investments)	**196**	22%	**170**	20%	**270**	23%	**244**	22%	**253**	22%	**209**	21%
Gas Distribution												
Enbridge Gas Distribution (EGD)	69	8%	110	13%	95	8%	136	12%	138	12%	123	12%
Other Gas Distribution Operations	20	2%	28	3%	30	3%	38	3%	38	3%	32	3%
Subtotal (Gas Distribution)	**89**	10%	**138**	16%	**125**	11%	**174**	16%	**176**	16%	**155**	16%
Gas Pipelines, Processing & Energy Services												
Enbridge Offshore Pipelines (22-74%	0	0%	(5)	-1%	(2)	0%	(7)	-1%	(7)	-1%	23	2%
Alliance Pipeline U.S. (50%)	18	2%	19	2%	25	2%	26	2%	26	2%	25	3%
Vector Pipeline (60%)	12	1%	13	2%	17	1%	18	2%	18	2%	15	2%
Aux Sable (42.7%)	47	5%	36	4%	66	6%	55	5%	55	5%	37	4%
Energy Services	31	3%	43	5%	44	4%	56	5%	55	5%	20	2%
Other	9	1%	16	2%	8	1%	15	1%	16	1%	3	0%
Subtotal (GPP&ES)	**117**	13%	**122**	15%	**158**	13%	**163**	15%	**163**	14%	**123**	12%
Subtotal of segments	903	100%	840	100%	1,180	100%	1,117	100%	1,128	100%	999	100%
Corporate and Noverco	63		5		55		(3)		(4)		(20)	
Net Income before Extras.*	**966**		**845**		**1,235**		**1,114**		**1,124**		**979**	
Extraordinary items (2)	(433)		(179)		(535)		(281)		(120)		(9)	
Net income avail. to common	533		666		700		833		1,004		970	
* After preferred share dividends.												

Net income (before extras) in 9M 2012 rose by $121 million (14%) compared with 9M 2011, to $966 million, as a result of increases in Liquids Pipelines, Sponsored Investments and Corporate, partly offset by declines in Gas Distribution and Gas Pipelines, Processing & Energy Services (all amounts before extras), as follows:

(1) **Liquids Pipelines** earnings rose by $91 million (22%), primarily as a result of the following:
- Canadian Mainline’s earnings rose by $51 million (19%), mainly due to implementation of the CTS, effective July 1, 2011, under which earnings are subject to changes in volume and operating costs. Increased revenues from higher-than-anticipated volume, as well as a 14% rise in the Mainline IJT residual benchmark toll (to $2.09 per barrel from $1.84 per barrel, effective in Q2 2012) as a result of a Lakehead toll reduction, were only partly offset by higher operating and administrative (O&A) costs, which were primarily due to higher employee-related costs and higher leak repairs.
- Higher earnings from (a) Spearhead Pipeline (higher volumes and tolls, due to increased demand to ship crude oil from the discounted market price at Cushing, Oklahoma), (b) Seaway Pipeline (incremental earnings from its acquisition in December 2011 and completion of its reversal in May 2012) and (c) Feeder Pipelines and Other (higher toll on Olympic Pipeline and higher volumes on Toledo Pipeline).

(2) **Sponsored Investments** earnings increased by $26 million (15%), mainly resulting from a rise in earnings from EIF of $23 million (72%), due to incremental earnings from the October 2011 renewable assets transfer from ENB to EIF, along with ENB’s higher economic interest in EIF since the transfer.

(3) **Gas Distribution** earnings fell by $49 million (36%), due primarily to EGD's earnings falling by $41 million (37%), mainly as a result of the negative impact of warmer weather ($37 million) and higher O&A and depreciation and amortization expenses.

(4) **Gas Pipelines, Processing & Energy Services** earnings fell by $5 million (4%), due to the following:
- Aux Sable earnings rose by $11 million (31%), mainly as a result of stronger realized fractionation margins and full-period earnings from assets acquired in July 2011.
- Energy Services earnings fell by $12 million (28%), primarily due to changing market conditions that resulted in fewer benefits from liquids marketing strategies.
- Other earnings fell by $7 million in 9M 2012, mainly due to the October 2011 renewable assets transfer referenced in Sponsored Investments above, as well as higher business development costs.

(5) **Corporate** results rose by $58 million, mainly due to deferred income tax recoveries in 9M 2012.

Outlook
- ENB has identified $35 billion of enterprise-wide growth capex investment opportunities for 2012 to 2016, categorized as commercially secured, highly probable unsecured and risked unsecured projects.
- ENB is targeting in excess of a 12% earnings per share (EPS) compounded annual growth rate (CAGR) from 2011 to 2016, supported by planned capex of $32.1 billion (see chart below and Major Growth Projects for details) as of early October 2012.
- Approximately 70% of total capex is related to liquids pipelines projects (supported by long-term contracts and the CTS agreement), with the balance allocated to (a) gas pipelines and processing (15%), (b) electric power, international and other (including renewable energy) (10%) and (c) gas distribution projects (5%).
- The projects are relatively well spread out, in terms of expected completion and initial earnings contribution.
- Approximately $3.8 billion was spent during 9M 2012.

Enbridge Day Disclosures - October 3, 2012			
Enbridge Inc.'s Funding Plan - Excluding Sponsored Vehicles (2012-2016)			
(C$ billions)			
Maintenance Capex	5.6		
Commercially Secured Growth Capex	12.7		
Highly Probable Unsecured Growth Capex	8.4		
Risked Unsecured Growth Capex	5.4		
Total Capex	32.1		
Less: Cash Flow Net of Dividends	(10.8)		
Net Funding Requirement	21.3		
	Debt		Equity
Total Requirement	15.2	Total Requirement	6.1
2012 - 2016 Maturities	3.3	Noverco Secondary Offering	(0.3)
Debt Already Issued	(0.5)	2012 Common Share Issuance	(0.4)
2012 Pref Share Issuances	(1.2)	2012 Pref Share Issuances	(1.2)
Debt Requirement	16.8	DRIP/ESOP	(2.3)
Company comments:		Equity Requirement	1.9
*Equity requirement falls well within remaining pref share issuance and sponsored vehicle drop down capacity for Q4 2012 - 2016			
* Debt requirement manageable for three issuers (ENB, EPI, EGD) for Q4 2012 - 2016, with bank facility backstop			
Source: Enbridge Day Presentations on October 3, 2012			

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Consolidated Financial Profile

ENB's conversion to U.S. GAAP from Canadian GAAP resulted in significant financial statement impacts, mainly due to the change to full consolidation from equity accounting for ENB's 21.8% interest in EEP and to equity accounting from proportional consolidation for the 50% interest in Seaway Pipeline.

- Major balance sheet differences at year-end 2011 included a $4.0 billion (25%) rise in total debt, a $2.9 billion (347%) rise in total non-controlling interests and a $1.4 billion (18%) drop in common equity. The last change comprised a $1.0 billion (21%) drop in retained earnings and a $0.4 billion increase in accumulated other comprehensive loss, relative to the Canadian GAAP accounting treatment.
- There were also material Cash Flow Statement differences for 2011, including a $281 million (12%) rise in cash flow before extras (DBRS-adjusted), a $2.3 billion (83%) increase in capex and long-term investments and a $1.2 billion (97%) reduction in acquisitions. EEP's US$1.1 billion of capex in 2011, while consolidated under U.S. GAAP, would not have appeared under Canadian GAAP, given EEP's treatment as an equity investment. In addition, ENB's US$1.2 billion acquisition of a 50% interest in Seaway Pipeline was treated as long-term investment under U.S. GAAP, though as an acquisition under Canadian GAAP.
- Differences in credit metrics between U.S. GAAP and Canadian GAAP are most pronounced with respect to cash flow-related measures. In the following table, DBRS has calculated adjusted ratios that convert certain consolidated (or proportionally consolidated) entities to equity accounting treatment, in order to enhance analysis of ENB's consolidated financial profile.

	US GAAP	US GAAP	US GAAP	US GAAP	Cdn GAAP	Cdn GAAP	Cdn GAAP
Enbridge Inc.	9 mos. ended Sept. 30		12 mos. ended	For the year ended December 31			
(CAD millions)	2012	2011	Sept. 30, 2012	2011	2011	2010	2009
Net income before extras	966	845	1,235	1,114	1,124	979	879
Depreciation and amortization	883	823	1,172	1,112	937	864	764
Deferred income taxes, AEDC and other	453	369	513	429	313	271	131
Cash Flow before extras	2,302	2,037	2,920	2,655	2,374	2,114	1,774
Capex and equity investments	(3,997)	(2,493)	(6,536)	(5,032)	(2,753)	(2,528)	(3,679)
Repayments by/(loans to) affiliates	4	10	1	7	10	(80)	(145)
Common and preferred dividends paid	(737)	(574)	(935)	(772)	(766)	(655)	(562)
Gross free cash flow (before work. cap.)	(2,428)	(1,020)	(4,550)	(3,142)	(1,135)	(1,149)	(2,612)
Changes in non-cash working capital items	(397)	376	(342)	431	329	(263)	243
Gross Free Cash Flow	(2,825)	(644)	(4,892)	(2,711)	(806)	(1,412)	(2,369)
Business acquisitions, net of cash	(221)	(28)	(226)	(33)	(1,208)	(116)	0
Proceeds on sale of invest. and other assets	642	283	648	289	(54)	39	483
Net Free Cash Flow	(2,404)	(389)	(4,470)	(2,455)	(2,068)	(1,489)	(1,886)
Inc. (dec.) in total debt	423	182	1,143	902	731	1,134	1,500
Inc.(dec.) in preferred shares	2,245	488	2,683	926	926	0	0
Inc.(dec.) in common equity	632	211	696	275	275	288	177
Inc. (dec.) in noncontrolling interests & other	107	288	518	699	214	(1)	(33)
Dec. (inc.) in cash balances	(1,003)	(780)	(570)	(347)	(78)	68	242
Funding Sources	2,404	389	4,470	2,455	2,068	1,489	1,886
Total debt in capital structure	60.2%	62.0%	60.2%	61.9%	60.8%	63.3%	63.2%
Cash flow/total debt	13.9%	14.1%	13.3%	13.1%	14.6%	13.8%	12.4%
Cash flow interest coverage	4.03	3.75	3.86	3.65	4.08	3.81	3.56
EBIT interest coverage (times)	2.67	2.75	2.77	2.83	2.93	2.42	2.14
Fixed-charges coverage (times)	2.38	2.73	2.51	2.78	2.89	2.38	2.11
Adjusted Total debt in capital structure (1)	59.6%	62.2%	59.6%	62.9%	59.3%	62.0%	62.1%
Adjusted Cash flow/total debt (1)	14.8%	13.8%	13.4%	12.2%	15.6%	14.6%	13.0%
Adjusted Cash flow interest coverage (1)	4.90	4.08	4.43	3.84	4.40	4.03	3.78
Adjusted EBIT interest coverage (times) (1)	3.38	3.17	3.47	3.31	3.23	2.59	2.30
Adjusted Fixed-charges coverage (times) (1)	2.80	3.12	2.96	3.22	3.18	2.55	2.26

(1) Certain entities adjusted to equity accounting basis. US GAAP: EEP and EIF. Cdn. GAAP: Alliance Pipeline U.S. and EIF.

- ENB's current financial profile is reasonable, given its relatively low business risk profile.
- Consolidated credit measures improved on both Canadian and U.S. GAAP bases in 2011 and 9M 2012. Rising cash flow from projects placed in service, combined with issuance of preferred shares ($3.2 billion), common shares ($0.9 billion) and EEP common units ($1.3 billion, included in non-controlling interests), with the latter relevant only to U.S. GAAP measures, supported higher capex while limiting debt growth.

- DBRS notes, however, that for the purposes of the credit metrics in the above table, approximately one-half of the outstanding preferred shares at September 30, 2012, were treated as debt equivalents.
- On an adjusted basis (treating EEP and EIF as equity investments, rather than consolidated entities) most of ENB's credit metrics in 9M 2012 were stronger than in 9M 2011, reflecting the above-noted factors as well as higher net income (before extras). The only exception was the adjusted fixed-charges coverage ratio, which incorporates preferred share dividend obligations ($69 million in 9M 2012, compared with only $5 million in 9M 2011) into the denominator and is one of DBRS's key metrics.
- During Q4 2012, ENB reached agreements for, among others: (1) the $0.3 billion Peace River Arch Gas Development, (2) deferral of the first two expansion phases of the $1.1 billion Cabin Gas Plant ($0.7 billion spent through Q3 2012), (3) transfer of certain crude oil storage and renewable generation assets to EIF for $1.164 billion and (4) the $1.8 billion Canadian Mainline Expansion from Edmonton to Hardisty.

Outlook

- ENB has identified $35 billion of enterprise-wide growth capex investment opportunities for 2012 to 2016, categorized as commercially secured, highly probable unsecured and risked unsecured projects (see Earnings and Outlook and Major Growth Projects).
- The Company's $32.1 billion capex plan includes a debt-funding requirement of $16.8 billion (including $3.3 billion for refinancing of debt maturities) from Q4 2012 to year-end 2016.
- This forecast is based on the Company's assumption that the $32.1 billion of total capex is funded by $10.8 billion of free cash flow after dividend payments.
- The forecast also includes $1.9 billion of equity funding from dividend re-investment and employee share ownership plans, sponsored vehicle drop downs (e.g., the pending EIF dropdown) and preferred share issuance.
- Please see Bank Lines and Debt Maturities for financing activities at ENB, EPI and EIF to date in Q4 2012.

Based on the size of the capex initiatives and net funding requirements in the latest plan, the Company will likely experience large free cash flow deficits, especially in the early years of the current plan, when common and preferred dividends ($0.9 billion, of which $0.6 billion was paid in cash, in the LTM September 30, 2012, and rising over time) are taken into account.

- Consequently, DBRS believes that the current capex and funding plans could have a negative impact on the Company's credit metrics during the early years of the current plan, before improvement in the later years (as the longer-dated projects are placed in service and begin to generate cash flow).
- However, DBRS expects that any such potential weakness would be shallower than experienced in 2008-2009, due to the shorter average construction period and lower average construction costs for the current portfolio of projects, which are relatively well spread out in terms of expected completion and initial earnings contribution.
- The Company's secured projects are largely protected from cost overruns, reducing ENB's exposure to the potential requirement for additional funding. Over the past few years, ENB has not had cost overruns with respect to its major projects.
- DBRS expects the Company's business risk profile to strengthen following completion of the major projects, as a result of the high weighting of capex toward liquids pipelines and natural gas projects, which have a low business risk profile, as noted elsewhere in this report.
- DBRS views renewable energy projects, which are subject to volume risk and exposure to O&M costs increases (following expiry of initial fixed-price O&M contracts), as having moderately higher business risk, although partly mitigated by their long-term contractual arrangements.
- These projects are expected to generate very good returns while mitigating many of the associated capital and operating risks, and are relatively well spread out in terms of expected completion.

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Non-Consolidated Financial Profile

ENB is a holding company consisting of the following (see Simplified Organization Chart in this report):

(1) Equity investments in a variety of entities, primarily regulated, that (a) issue their own debt (e.g., EPI, EGD, EIF and EEP) or have project financing debt (e.g., Southern Lights) and (b) rely on the Company for financing (e.g., Athabasca Pipeline and Spearhead Pipeline).

(2) Loans to (and from) various related parties.

- External funds are raised to support equity investments and debt financing for subsidiaries (accounting for about one-quarter of segment earnings in LTM September 30, 2012) that have not issued public debt.
- Project finance debt is non-recourse to ENB (e.g., Alliance Pipeline and Southern Lights). However, for entities that raise their own funding, the risk remains that ENB could contribute additional equity if problems were to develop in its investments, especially EEP, which is critical to ENB's business profile.
- Development-stage projects entail execution risk, while investments that are at least partly U.S.-based (EEP, Southern Light, Aux Sable, Alberta Clipper U.S., Spearhead, Alliance U.S., Seaway, Enbridge Offshore Pipelines, and Vector, accounting for 35% of segment earnings for LTM September 30, 2012), as well as the Canadian Mainline under the CTS, result in exposure to currency risk – although this is substantially mitigated through hedging activities.
- Modest commodity price risk at EEP and Aux Sable is also mitigated through hedging activities.

	US GAAP	C.GAAP	C.GAAP	C.GAAP	C.GAAP
Enbridge Inc.	As at Sept. 30	As at December 31			
Non-Consolidated Asset Coverage (CAD billions)	2012	2011	2010	2009	2008
Total consolidated assets (A)	45.0	34.3	30.2	28.3	24.7
Less:					
Minority interest (EEM/EGD/EIF) (B)	3.3	0.8	0.7	0.7	0.8
External debt of subsidiaries:					
Enbridge Gas Distribution debt	3.0	3.1	2.4	2.7	3.2
Enbridge Pipelines Inc. debt	2.9	2.8	4.1	2.6	1.8
Enbridge Income Fund debt	1.2	0.7	0.4	0.3	0.3
Alliance Canada debt	0.0	0.6	0.7	0.8	0.8
Alliance U.S./Aux Sable/Vector debt	0.1	0.5	0.7	0.5	0.5
Southern Lights Debt	1.4	1.5	1.5	1.5	1.4
Enbridge Energy Partners debt	5.0	0.0	0.0	0.0	0.0
Sub-total external debt of subsidiaries (C)	13.6	9.2	9.8	8.4	8.0
Net consolidated assets (A-B-C=D)	28.1	24.3	19.8	19.1	15.9
Corporate level (unconsolidated) debt (E)	6.9	7.2	6.8	5.9	4.9
Total consolidated debt (excl.pref. component) (F)	20.5	16.2	15.3	14.3	13.2
Total preferred shares (G)	3.3	1.1	0.1	0.1	0.1
Common (adj.for AOCI & non-qualifying derivatives) (H)	8.8	8.6	8.1	7.5	6.4
Net asset coverage of debt (excl.pref. component) (D/E)	4.1	3.4	2.9	3.2	3.2
Net asset coverage of debt and all pref (D/E+G)	2.8	2.9	2.9	3.2	3.2
Corporate level debt/total consolidated debt (E)/(F)	34%	44%	45%	41%	37%
Corp. level debt & pref./consol. debt & pref (E+G)/(F+G)	43%	48%	45%	42%	38%
Corp. level debt/Total capital (E)/(E+G+H)	36%	43%	45%	44%	43%
Corp. level debt + debt component of pref/Total capital	45%	43%	45%	44%	43%

- From a debtholder's perspective, the Company's non-consolidated balance sheet ratios improved in 9M 2012 from year-end 2011, largely due to significant issuance of preferred and common shares (see Consolidated Financial Profile). However, with approximately one-half of outstanding preferred shares at September 30, 2012, treated as debt equivalents, balance sheet leverage weakened modestly in the period.
- Non-consolidated debt-to-capital (excluding the debt component of preferred shares) fell to 36% at September 30, 2012, from 43% at year-end 2011 and 45% at year-end 2010. However, including the debt component of preferred shares, the ratio rose to 45% from 43% and 45% at the same dates.
- Similarly, net asset coverage of debt (excluding the debt component of preferred shares) rose to 4.1 times from 3.4 times and 2.6 times, while the comparable ratio, including the debt component of preferred shares, fell to 2.8 times from 2.9 times and 2.9 times.
- DBRS notes that, while the above metrics are not directly comparable due to the conversion to U.S. GAAP from Canadian GAAP, the direction of the changes is likely to remain consistent.

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Enbridge Inc. (CAD millions) (Cdn. GAAP)	For the year ended December 31			
Dividend & Income Transactions	2011	2010	2009	2008
Dividend income, net of O&A expenses (I)	922	793	535	558
Interest income (expense) from (to) affiliates, net (J)	56	7	106	195
Dividend and interest income, net (K)	978	800	641	753
External interest expense (L)	(307)	(300)	(237)	(224)
Dividend income after external interest expense, net (M)	671	500	404	529
Common dividends paid in cash (1)	(530)	(426)	(414)	(359)
Preferred dividends paid	(7)	(7)	(7)	(7)
Net remaining after external dividends	134	67	(17)	163
(1) Net of amounts reinvested in common shares (2011 - $229; 2010 - $222; 2009 -$141; 2008 - $130).				
Dividend income/corporate level debt (I/E)	12.8%	11.7%	9.0%	11.4%
Dividend income/external interest expense (I/L)	3.00	2.64	2.26	2.49
Dividend inc. after exter.int.exp./corp. level debt (M/E)	9.3%	7.4%	6.8%	10.8%
Dividend & interest income/external interest exp. (K/L)	3.19	2.67	2.70	3.36
Dividend inc./exter. int. exp.& pref.divs (I/L+O)	2.94	2.58	2.19	2.42
Dividend & int.inc./ext. int. exp.& pref.divs (K/L+O)	3.11	2.61	2.63	3.26
Affiliate Transactions				
Interest Income from Loans to Affiliates	122	117	171	218
Interest Expense on Loans from Affiliates	(66)	(110)	(65)	(23)
Interest Inc. (Exp.) from (to) Affiliates, Net	56	7	106	195
Affiliate Balances				
Loans to Affiliates (Asset)	3,767	2,075	1,955	3,217
Loans from Affiliates (Liability)	740	2,236	3,316	1,112
Loans to Affiliates, net (Net Asset)	3,027	(161)	(1,361)	2,105

- As expected, key non-consolidated interest coverage ratios and dividend-to-debt ratios continued to improve from low 2009 levels, although the dividend income after external interest-to-corporate level debt ratio remains below the 2008 level.
- Approximately one-quarter of ENB's segment earnings for LTM September 30, 2012, were derived from entities with no external debt, thereby providing a stream of unencumbered dividends to the Company.
- The remaining three-quarters of segment earnings were derived mostly from entities with low-risk, mostly regulated operations that generate relatively stable earnings, including EPI, EGD, EIF and EEP (accounting for a combined 60% of segment earnings), which also provide a steady stream of dividends to ENB.
- Direct debt raised at ENB and onlent to subsidiaries resulted in rising external interest expense.
- This was offset by higher dividend income and net interest income from subsidiaries, fully supporting the Company's common (net of DRIP) and preferred dividends on a non-consolidated basis in 2011.
- In 2009, net interest income from subsidiaries declined significantly, as ENB repatriated $1.3 billion of loans to affiliates and borrowed an additional $2.2 billion from affiliates while raising common dividends.
- In 2010, higher net dividend income (mainly a result of the completion of ENB's major pipeline projects) more than offset higher external interest expense and lower net interest income (largely due to repayment to ENB of $1.1 billion of loans due from affiliates).
- In 2011, ENB received repayment of $1.5 billion from affiliates while raising loans to affiliates by $1.7 billion. Net dividend and interest income continued to rise and was sufficient to fully support the Company's common (net of DRIP) and preferred dividends.

Outlook

- DBRS expects that ENB's total external debt will continue to rise as a proportion of total consolidated debt, as a result of its ongoing growth capex plans.
- DBRS expects ENB to continue to mitigate its relatively high non-consolidated debt-to-capital ratio (including the debt component of preferred shares), which was 45% as at September 30, 2012, with an expanding base of unencumbered earnings-generating subsidiaries and investments.

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Bank Lines and Debt Maturities

At September 30, 2012, ENB and its consolidated subsidiaries (including EPI, EGD, EIF and EEP, but excluding the Southern Lights project financing), had $11.6 billion of combined committed credit facilities, of which $3.4 billion was drawn or allocated to backstop commercial paper.

- Of this amount, $6.6 billion of facilities are at ENB, providing support to its $2.5 billion CP program.
- At September 30, 2012, Southern Lights had $1.5 billion of project financing credit facilities maturing in 2014, of which $1.4 billion was drawn.

Debt Maturities

($ millions) (as at September 30,2012) (1)	Q4 2012	2013	2014	2015	2016+
Long-term debt – Enbridge Inc. (direct)	0	450	400	650	3,518
Long-term debt – Enbridge Pipelines Inc. (direct)	250	0	0	250	2,225
Long-term debt – Enbridge Gas Distribution Inc.	0	0	400	0	1,980
Long-term debt – Enbridge Income Fund (direct)	0	0	90	0	825
Long-term debt – Enbridge Energy Partners, L.P. (2)	100	200	200	0	4,472
Long-term debt – total	350	650	1,090	900	13,020
% of long-term debt	2%	4%	7%	6%	81%

(1) All amounts excludes short-term debt, commercial paper and draws under credit facilities. (2) Amounts in US dollars.

- In Q4 2012, ENB issued $400 million of preferred shares and a $350 million 3.19% MTN issue maturing on December 5, 2022.
- In Q4 2012, EPI issued a $150 million 2.932% MTN issue maturing on November 30, 2022.
- In Q4 2012, EIF issued a $200 million floating rate MTN issue maturing on November 28, 2014.
- Debt maturities are relatively well spread out on both a consolidated and non-consolidated basis, and well within the Company's ability to refinance, although significant new issuance is expected over the medium term, in order to fund the large capex program.
- ENB has maintained adequate liquidity on a consolidated basis and on a direct basis.

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Major Growth Projects

The following table summarizes ENB's $20 billion of commercially secured projects, of which approximately $5.7 billion had been spent through Q3 2012. The increase from $12.7 billion on October 3, 2012, reflects the transition of a number of projects from the "highly probable" category.

Enbridge Inc.'s Commercially Secured Projects		Expected	Initial	Expected	Capital	
Liquids Pipeline Projects		Completion	Capacity	Capital	Spent to	Status at
Alberta Regional Infrastructure	Location	Date	Increase	Cost	Sept.30/12	Sept.30/12
Edmonton Terminal Expansion	Alberta	Dec. 2012	1 MMbbls	$0.3	$0.1	Under construction
Woodland Pipeline (Kearl Oil Sands to Cheecham Terminal)	Alberta	late 2012	200,000 b/d	$0.3	$0.3	Substantially complete
Wood Buffalo Pipeline (Athabasca to Cheecham Terminal)	Alberta	Q4 2012	n/a	$0.4	$0.3	Substantially complete
Waupisoo Pipeline Expansion (Cheecham to Edmonton)	Alberta	2012- 13	255,000 b/d	$0.4	$0.2	Under construction
Norealis Pipeline (Sunrise Oil Sands to Cheecham Terminal)	Alberta	late 2013	90,000 b/d	$0.5	$0.2	Under construction
Suncor Bitumen Blend Project	Alberta	Q2 2013	n/a	$0.2	$0.1	Under construction
Athabasca Pipeline Expansion (Cheecham to Hardisty)	Alberta	2013- 14	570,000 b/d	$0.4	$0.2	Under construction
Athabasca Pipeline Twinning (Kirby Lake to Hardisty)	Alberta	2015	450,000 b/d	$1.2	minimal	Pre-construction
U.S. Gulf Coast Access						
Seaway Reversal, Twinning & Lateral (50/50 with Enterprise)	USGC	2012- 14	400,000 b/d	US$2.4	US$1.3	Under construction
Flanagan South Pipeline (twin Spearhead Pipeline)	Midwest	mid-2014	585,000 b/d	US$2.8	US$0.1	Pre-construction
Mainline Capacity Expansions						
Cdn. Mainline Expansion (Edmonton to Hardisty) **(EPI)**	Alberta	mid-2015	570,000 b/d	$1.8	minimal	Pre-construction
Canadian Mainline Expansion (Hardisty to Gretna) **(EPI)**	Alberta	mid-2014	120,000 b/d	$0.2	minimal	Pre-construction
Eastern Access						
Eastern Access - Toledo Pipeline Expansion (Line 79)	Midwest	Q2 2013	n/a	US$0.2	minimal	Pre-construction
Eastern Access - Line 9 Reversal	Midwest	mid-2014	n/a	$0.3	minimal	Pre-construction
Sponsored Investments						
Bakken Expansion Program **(EEP)**	North Dakota	Q1 2013	combined	US$0.4	US$0.2	Under construction
Bakken Expansion Program **(EIF)**	Saskatchewan	Q1 2013	145,000 b/d	$0.2	$0.1	Under construction
Cushing Terminal Storage Expansion Project **(EEP)**	Midwest	2012- 13	4.4 MMbbls	US$0.2	US$0.1	Under construction
South Haynesville Shale Expansion **(EEP)**	Texas	2012-plus	n/a	US$0.3	US$0.2	Under construction
Berthold Rail Project **(EEP)**	North Dakota	Q1 2013	80,000 b/d	US$0.1	US$0.1	Under construction
Ajax Cryogenic Processing Plant **(EEP)**	Texas	mid-2013	150 MMcf/d	US$0.2	US$0.1	Under construction
Bakken Access Program **(EEP)**	Midwest	early 2013	100,000 b/d	US$0.1	minimal	Under construction
Texas Express Pipeline **(35% EEP)**	Texas	mid-2013	280,000 b/d	US$0.4	US$0.1	Under construction
Line 6B Replacement **(EEP)**	Midwest	2013	n/a	US$0.3	US$0.1	Under construction
Eastern Access Expansion **(60% ENB / 40% EEP)**	Midwest	2013- 14	n/a	US$2.2	US$0.2	Pre-construction
Lakehead System Mainline Expansion **(EEP)**	Midwest	mid-2014	n/a	US$0.4	minimal	Pre-construction
Gas Pipelines, Processing and Energy Services						
Silver State North Solar Project	Nevada	2012	50 MW	US$0.2	US$0.2	Complete
Lac Alfred Wind Project **(50% ENB)**	Quebec	2012- 13	300 MW	$0.3	$0.2	Under construction
Cabin Gas Plant **(71% ENB)**	B.C.	TBD	800 MMcf/d	$1.1	$0.7	Expansions deferred
Peace River Arch Gas Development	Alberta	2012- 13	n/a	$0.3	minimal	Pre-construction
Tioga Pipeline Lateral **(Alliance US)**	North Dakota	mid-2013	n/a	US$0.1	minimal	Under construction
Venice Condensate Stabilization Facility	Louisiana	late 2013	12,000 b/d	US$0.2	US$0.1	Under construction
Walker Ridge Gas Gathering System (Ultra deepwater)	GOM	2014	100 MMcf/d	US$0.4	US$0.1	Pre-construction
Big Foot Oil Lateral (Ultra deepwater development)	GOM	2014	100,000 b/d	US$0.2	US$0.1	Pre-construction
Gas Distribution						
Greater Toronto Area Project	Ontario	2016	n/a	$0.6	minimal	Pre-construction
Corporate						
Montana-Alberta Tie-Line (Great Falls, Montana to Lethbridge Alberta)		2013- 14	600 MW	US$0.4	US$0.3	Under construction
EEP = Enbridge Energy Partners, L.P. EIF = Enbridge Income Fund EPI = Enbridge Pipelines Inc. USGC = U.S. Gulf Coast GOM = Gulf of Mexico						
MMbbls = millions of barrels; b/d = barrels per day; MW = megawatts; MMcf/d = millions of cubic feet per day n/a = not available.						

- Some of these projects have been announced in recent months (i.e., the $0.6 billion Greater Toronto Area Project and the $0.2 billion Suncor Bitumen Blend Project in September, the $0.3 billion Peace River Arch Gas Development in October and the $1.8 billion Canadian Mainline Expansion from Edmonton to Hardisty in November).
- These projects are expected to generate very good returns while mitigating many of the associated capital and operating risks, and are relatively well spread out in terms of expected completion.

Business Segments

ENB operates in the following segments (see the Earnings and Outlook section for major investments):

(1) **Liquids Pipelines** (53% of segment earnings for LTM September 30, 2012) includes the following:
- Enbridge System transports crude oil from Edmonton to the Manitoba-U.S. border, where it connects with the Lakehead System, then reconnects with the Enbridge System at the Ontario-U.S. border.
- Enbridge Regional Oil Sands System includes the Athabasca and Waupisoo pipelines, the MacKay River, Christina Lake, Surmont and Long Lake facilities, as well as the Hardisty Caverns Limited Partnership, which provides storage service and three large terminals.
- Includes the Southern Lights and Spearhead pipelines, as well as interests in the Olympic Pipeline (85% owned) and Seaway Pipeline (50% owned), the NW System, a number of feeder pipelines in the United States and contract tankage facilities.
- Interests in commercially secured projects noted in the Major Growth Projects section of this report.

(2) **Sponsored Investments** (23% of segment earnings) includes the following:
- EEP (21.8% interest), a master limited partnership that owns the core Lakehead System, the North Dakota and Mid-Continent crude oil pipelines, U.S. natural gas gathering, processing and marketing assets and a one-third interest in Alberta Clipper U.S.
- Enbridge Energy, L.P., which owns a two-thirds interest in Alberta Clipper U.S.
- EIF (69% economic interest), which owns 50% of Alliance Pipeline Limited Partnership, the Canadian portion of the Alliance Pipeline, 100% of Enbridge Pipelines (Saskatchewan) Inc., a 50% interest in NRGreen waste heat recovery facilities and Sunbridge wind power projects, along with a 33% interest in the Magrath and Chin Chute wind power projects (collectively, Green Power). In October 2011, EIF acquired Ontario Wind Project, Talbot Wind Energy Project and Sarnia Solar Project from ENB. In October 2012, EIF agreed to acquire crude oil storage and renewable generation assets from ENB. The transaction is expected to close in December 2012, subject to regulatory and third-party approvals.
- Interests in commercially secured projects, as noted in the Major Growth Projects section of this report.

(3) **Gas Distribution** (11% of segment earnings) includes the following:
- EGD, which provides natural gas distribution, storage and transmission services in the central, eastern and Niagara Peninsula regions of Ontario, is a regulated utility serving approximately 2.0 million customers.
- Interests in other gas distribution franchises, including Gazifière, Niagara Gas and St. Lawrence Gas.

(4) **Gas Pipelines, Processing and Energy Services** (13% of segment earnings) includes the following:
- Enbridge Offshore Pipelines includes 13 natural gas gathering and FERC-regulated pipelines and an oil pipeline in the Gulf of Mexico, as well as projects (see Major Growth Projects).
- 50% interest in Alliance Pipeline L.P., the U.S. section of the Alliance Pipeline.
- 60% interest in Vector Pipeline Limited Partnership (Vector Pipeline).
- 42.7% interest in Aux Sable Liquid Products Inc. (Aux Sable).
- Enbridge Energy Services provides natural gas, crude oil and NGL marketing services and markets natural gas to optimize ENB's commitments on the Alliance and Vector pipelines.
- Other includes renewable energy projects (see Major Growth Projects).
- A 71% interest in Phases 1 and 2 of Cabin. Upon completion of Phases 1 and 2, which has been deferred, ENB's total investment was expected to be $1.1 billion, with $0.7 billion spent through Q3 2012. Cabin (Canadian natural gas processing) is a new business activity for ENB.

(5) **Corporate** includes ENB's equity interest in Noverco Inc. (Noverco), through ownership of 38.9% of the common shares and a cost investment in preferred shares and the MATL project. MATL (electricity transmission) represents a new business activity for ENB.

Regulation

Enbridge/Lakehead System

- Mainline is regulated by the NEB.
- Effective July 1, 2011, EPI entered into the CTS, which provides for a joint tariff for volumes originating in western Canada that are transported on the Lakehead System. Concurrently, EEP entered into the IJT with EPI that ensures that the joint tariff revenues are allocated based on the existing Lakehead System rate structures, resulting in no direct impact to the Lakehead System's tolls.
- Therefore, any shortfall in tolls (e.g., due to lower throughput) under the CTS for the Lakehead System, compared with the latter's existing agreements, would potentially reduce the tolls available to the Mainline.
- Consequently, the CTS introduced volume and operational risks to the Mainline through a fixed-toll methodology (based on tolls of US$3.85 per barrel of heavy crude oil from Hardisty, Alberta, to Chicago, Illinois, adjusted by 75% of the Canadian Gross Domestic Producer Implicit Price (GDPP) Index for the remaining nine years of the settlement), as opposed to the cost-of-service basis for the previous tolling arrangements.

Enbridge/Lakehead's Tariff Agreement (the Agreement) with shippers, with respect to pipeline expansions, provides downside protection and incentives to EEP.
(1) With respect to the System Expansion Program (SEP) II expansion (which added 100,000 b/d to capacity in 1998), the Agreement provides for the following terms until 2013:

- A negotiated cost-of-service toll structure with an allowed ROE (currently 8.6%) based on throughput.
- A guaranteed minimum ROE of 7.5% if utilization is 50% or less.
- NEB base multi-pipeline ROE plus 3%, with 100% capacity utilization, subject to a cap ROE of 15%.

(2) With respect to the Terrace capacity expansions (which added 350,000 b/d in phases to Enbridge System capacity in mid-2003), the Agreement currently provides for a fixed toll surcharge of US$0.013 per barrel to EEP through 2013, the term of the agreement. In addition, an adjustment (none in 2011) is made to the Terrace surcharge, based on the annual actual average pumping exiting Clearbrook, Minnesota.

(3) With respect to the Southern Access Mainline Expansion (which added 400,000 b/d of incremental heavy oil capacity from Hardisty, Alberta, to Flanagan, Illinois, in 2009), the U.S. Federal Energy Regulatory Commission (FERC) approved the 30-year cost-of-service tolling agreement, which results in a 9% real ROE, with an annual inflation adjustment added to the rate base, collected over time and allowing for collection of FERC's income tax allowance. The U.S. tolling principles include a 45% debt/55% equity capital structure.

(4) With respect to Alberta Clipper (which added 450,000 b/d of incremental heavy oil capacity from Hardisty to Superior, Wisconsin, where it connects with Southern Access, in 2010), U.S. tolling principles include a renewable 15-year cost-of-service tolling agreement protecting EEP against volume risk, indexed cost recovery and a floating ROE equal to the NEB's multi-pipeline rate (currently at 8.6%) plus 2.25%. The U.S. tolling principles will include a 45% debt/55% equity capital structure.

(5) A Facilities Surcharge Mechanism (FSM) is based on the cost of service model with a 45% debt/55% equity capital structure plus an income tax allowance adjustment.

- The average toll for crude oil movements from the Canadian border to Chicago fell by US$0.22 to US$1.60 per barrel, effective April 1, 2012.
- Effective July 1, 2012, indexed transportation rates rose by US$0.07 to US$1.67 per barrel, in connection with the annual index rate ceiling adjustment.
- The toll remains very competitive and very low (about 2%) relative to the current West Texas Intermediate (WTI) price of crude oil.

Enbridge Gas Distribution

The OEB regulates EGD's natural gas storage, transmission and distribution operations in Ontario. EGD is currently subject to a multi-year Incentive Regulation plan that runs from 2008 to 2012 as summarized below.

Gas Distribution

- Allowance for inflationary rate increases, offset by a fixed productivity factor for each of the five years. EGD continues to bear weather-related volume risk (see Challenge (4), above).
- A higher component of fixed monthly customer charges reduced seasonality of earnings.
- Continued pass-through of gas commodity, upstream transportation and demand side management costs.
- EGD's 2007 ROE of 8.39% and equity component at 36% remain unchanged throughout the IR period.
- The Gas Cost Deferral Accounts, Storage and Other Deferral Accounts remain in place.
- An earnings-sharing mechanism between EGD and its ratepayers applies if, during any calendar year, the actual ROE exceeds the allowed ROE by more than 100 basis points. In that event, the excess earnings would be shared 50/50 between EGD and its customers.
- Enbridge estimated the customer portion of 2011 earnings over the allowed threshold at $14 million ($19 million in each of 2010 and 2009, and $6 million in 2008).

Gas Storage

- The OEB regulates neither the prices of storage services to customers outside EGD's franchise area nor the prices of new storage services to customers within the franchise area.
- Existing customers within the Company's franchise area continue to be charged at cost-based rates.
- In December 2009, the OEB adjusted its formulaic approach to determining allowed ROE, resulting in an initial ROE of 9.75% to be incorporated in 2010 Cost of Service applications.
- EGD will likely benefit from the new allowed ROE methodology in 2013, upon commencement of a cost-of-service based methodology for that year.
- In November 2012, the OEB approved EGD's settlement agreement relating to its 2013 rate application. The settlement resolved all elements of the rate application, except the requested change in equity thickness (EGD requested an increase to 40% from 36%), which was heard by the OEB in late November.
- EGD expects to file a "next generation" IR plan for the 2014 to 2018 period during 2013.

Simplified Organizational Chart

ENBRIDGE INC.
Simplified Organization Chart
Long-Term Debt as at Sept. 30, 2012

Enbridge Inc. (ENB)
MTNs & Unsecured Debentures — A (low)
Cum. Red. Pref. Shares — Pfd-2 (low)
Commercial Paper — R-1 (low)
$20.5 billion debt (consolidated)
$6.9 billion debt (direct) (estimate)
$3.3 billion preferred shares

Liquids Pipelines

Enbridge Pipelines Inc. (EPI)
MTNs & Unsecured Debentures — "A"
Commercial Paper — R-1 (low)
$9.3 billion debt (consolidated)
$1.4 billion debt (Southern Lights)
$5.0 billion debt (EEP; 21.8% owned)
$2.9 billion (direct)

Southern Lights $1.4 billion debt (direct)

Other Operations
Athabasca System
Waupisoo Pipeline
Spearhead Pipeline
Seaway Pipeline
Other feeder pipelines
No direct debt

Gas Pipelines, Processing & Energy Services

Alliance Pipeline L.P.
(Alliance U.S.; 50% owned)
Senior Secured Notes — A (low)
$0.6 billion total debt (ENB: 50% equity inv.)

Other Operations
Offshore pipelines (22%-75%)
Vector Pipeline (60%)
Aux Sable (42.7%)
Energy Services
Minimal direct debt

Sponsored Investments

Enbridge Income Fund (EIF)
(35.4% owned)
Senior Unsecured LT Notes — BBB (high)
$1.2 billion (consolidated)
$1.2 billion (direct)

Alliance Pipeline Limited Partnership
(Alliance Canada; 50% owned by EIF)
Senior Secured Notes — A (low)
Senior Unsecured Notes — BBB (high)
$1.2 billion total debt (ENB: equity investment)

Enbridge Energy Partners, L.P. (EEP)
(21.8% owned)
Senior Unsecured Notes — BBB
Junior Subordinated Notes — BB (high)
Commercial Paper — R-2 (middle)
US$5.0 billion (direct)
US$5.5 billion (consolidated)

Gas Distribution

Enbridge Gas Distribution (EGD)
Unsecured Debentures & MTNs — A
Preferred Shares — Pfd-2 (low)
Commercial Paper — R-1 (low)
$3.0 billion debt (direct)
$0.1 billion preferred shares

Other Gas Distribution Operations
Gazifere
Niagara Gas
Enbridge Gas New Brunswick (69.6%)
Other
No direct debt

Corporate

Other Operations
Noverco Preferred Shares
Other
No direct debt

Sept. 30, 2012 Consolidated Debt ($B)			Segment Earnings ($ MM)*	
EGD	$3.0	15%	$95	8%
EPI	2.9	14%	387	33%
EEP	5.0	24%	154	13%
Vector Pipeline	0.1	0%	17	1%
Alliance Pipeline L.P.	0.0	0%	25	2%
Aux Sable	0.0	0%	66	6%
Southern Lights	1.4	7%	74	6%
Enbridge Income Fund	1.2	6%	74	6%
External Sub-total	**$13.6**	**66%**	**$892**	**76%**
Direct Debt (estimate)	6.9	34%	288	24%
Consolidated	$20.5	100%	$1,180	100%

*Net income before extras for the 12 months ending Sept. 30, 2012.

Enbridge Inc.

Report Date:
December 5, 2012

Enbridge Inc. (Consolidated)

	US GAAP	US GAAP	Cdn GAAP		US GAAP	US GAAP	Cdn GAAP
Balance Sheet (CAD millions)	Sept. 30	Dec. 31	Dec. 31		Sept. 30	Dec. 31	Dec. 31
Assets	2012	2011	2011	**Liabilities and Equity**	2012	2011	2011
Cash and equivalents	1,726	723	420	Short-term debt	935	650	650
Accounts rec. and other	3,685	4,083	3,136	A/P and accrued liab.	4,954	5,172	3,836
Inventory	877	823	739	L.t. debt due in one year	748	354	374
Current assets	6,288	5,629	4,295	Current liabilities	6,637	6,176	4,860
Prop., plant and equip., net	31,339	28,941	22,623	Long-term debt	18,778	19,251	15,208
Long-term investments	3,272	3,160	2,540	Preferred shares	3,316	1,056	1,056
Def. amounts and other assets	2,846	2,667	3,220	Other long-term liabs.	5,463	4,895	4,588
Intangibles and goodwill	1,255	1,151	1,624	Noncontrolling interests	4,051	3,781	846
Future income taxes	8	29	41	Common equity	6,763	6,418	7,785
Total	45,008	41,577	34,343	Total	45,008	41,577	34,343

(CAD millions where applicable)	US GAAP	US GAAP	US GAAP	US GAAP	Cdn GAAP	Cdn GAAP	Cdn GAAP
Balance Sheet and	9 mos. ended Sept. 30		12 mos. ended	For the year ended December 31			
Liquidity Ratios (1)	2012	2011	Sept. 30, 2012	2011	2011	2010	2009
Current ratio	0.95	1.85	0.95	0.91	0.88	1.12	0.95
Net debt in capital structure	58.2%	60.6%	58.2%	61.1%	60.2%	62.8%	62.6%
Total debt in capital structure	60.2%	62.0%	60.2%	61.9%	60.8%	63.3%	63.2%
Common equity in capital structure	24.0%	25.0%	24.0%	23.3%	32.1%	33.5%	33.0%
Cash flow/total debt	13.9%	14.1%	13.3%	13.1%	14.6%	13.8%	12.4%
(Cash flow - dividends)/net capex	0.43	0.67	0.40	0.54	0.63	0.61	0.37
Common divs/net income (before extras)	69.2%	67.3%	69.5%	68.1%	67.5%	66.2%	63.1%
Total divs/net income (before extras)	76.3%	67.9%	75.7%	69.3%	68.1%	66.9%	63.9%
Coverage Ratios (times) (2)							
EBIT interest coverage	2.67	2.75	2.77	2.83	2.93	2.42	2.14
EBITDA interest coverage	3.83	3.86	3.92	3.94	4.14	3.56	3.25
Fixed-charges coverage	2.38	2.73	2.51	2.78	2.89	2.38	2.11
Cash flow interest coverage	4.03	3.75	3.86	3.65	4.08	3.81	3.56
Profitability Ratios (before extras.)							
Operating margin	7.9%	8.8%	8.7%	9.3%	9.9%	10.0%	10.2%
Profit margin	5.3%	4.3%	4.9%	4.1%	5.8%	6.5%	7.1%
Return on common equity	18.1%	16.7%	17.1%	16.9%	14.7%	13.3%	12.8%
Return on capital	5.5%	6.0%	5.5%	5.8%	6.5%	6.3%	6.0%
Segmented Earnings (CAD millions)							
Liquids Pipelines	501	410	627	536	536	512	454
Sponsored Investments	196	170	270	244	253	209	151
Gas Distribution	89	138	125	174	176	155	171
Gas Pipelines, Processing & Energy Servic	117	122	158	163	163	123	116
Corporate and Other	63	5	55	(3)	(4)	(20)	(13)
Net income before extras	966	845	1,235	1,114	1,124	979	879
Reported earnings	533	666	700	833	1,004	970	1,562
Selected Financial Data (CAD millions)							
Cash flow (bef. working capital changes)	2,302	2,037	2,920	2,655	2,374	2,114	1,774
Capex, equity investments, other	(3,993)	(2,483)	(6,535)	(5,025)	(2,743)	(2,608)	(3,824)
Common and preferred dividends paid	(737)	(574)	(935)	(772)	(766)	(655)	(562)
Free cash flow (before work. cap. changes)	(2,428)	(1,020)	(4,550)	(3,142)	(1,135)	(1,149)	(2,612)
Changes in working capital items	(397)	376	(342)	431	329	(263)	243
Gross free cash flow	(2,825)	(644)	(4,892)	(2,711)	(806)	(1,412)	(2,369)
Other investing activities	421	255	422	256	(1,262)	(77)	483
Net free cash flow	(2,404)	(389)	(4,470)	(2,455)	(2,068)	(1,489)	(1,886)
Operating Statistics							
Liquids pipelines volumes ('000s of b/d)	3,022	2,661	3,070	2,709	2,709	2,879	2,714
Gas pipelines volumes (Bcf/d)	4.611	4.726	4.598	4.684	4.684	5.018	4.972
Gas distribution throughput (bcf)	272	311	387	426	426	409	408
Gas distribution - Degree day deficiency	85%	105%	93%	100%	100%	98%	107%

(1) DBRS allocates debt and equity equivalents to preferred shares and noncontrolling interest.

(2) Excludes AFUDC and capitalized interest.

Enbridge Inc.

Report Date:
December 5, 2012

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A (low)	Confirmed	Stable
Medium-Term Notes & Unsecured Debentures	A (low)	Confirmed	Stable
Cumulative Redeemable Preferred Shares	Pfd-2 (low)	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating History

	Current	2011	2010	2009	2008	2007
Issuer Rating	A (low)	NR	NR	NR	NR	NR
MTNs & Unsecured Debt	A (low)	A (low)	A	A	A	A
Cumulative Redeemable Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

Related Research

- Enbridge Pipelines Inc. Rating Report, December 5, 2012.
- Enbridge Income Fund Rating Report, October 30, 2012.
- Enbridge Energy Partners, L.P. Rating Report, October 25, 2012.
- Enbridge Gas Distribution Rating Report, June 28, 2012.

Note:
All figures are in Canadian dollars unless otherwise noted.

MOODY'S
INVESTORS SERVICE

Credit Opinion: Enbridge Inc.

Global Credit Research - 08 Dec 2011

Calgary, Alberta, Canada

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured	Baa1
Subordinate Shelf	(P)Baa2
Pref. Stock -Dom Curr	Baa3
Enbridge Energy Partners, L.P.	
Outlook	Stable
Issuer Rating	Baa2
Senior Unsecured	Baa2
Jr Subordinate	Baa3
Commercial Paper	P-2
Enbridge Income Fund	
Outlook	Stable
Senior Unsecured -Dom Curr	Baa2
Enbridge Energy Limited Partnership	
Outlook	Stable
Senior Unsecured	Baa1
Subordinate Shelf	(P)Baa2

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Key Indicators

[1]**Enbridge Inc.**

	[2]LTM	2010	2009	2008	2007	2006
FFO + Interest / Interest	**4.2x**	**3.7x**	**3.4x**	**3.3x**	**3.1x**	**3.0x**
FFO / Debt	**16.0%**	**13.4%**	**11.9%**	**10.9%**	**12.2%**	**11.4%**
Debt / Capitalization	**58.4%**	**59.4%**	**59.0%**	**61.1%**	**61.2%**	**62.1%**
Operating Margin	**8.8%**	**9.9%**	**10.1%**	**8.3%**	**9.6%**	**10.7%**

[1] All ratios are calculated in accordance with Moody's Natural Gas Pipelines Methodology. In addition, Moody's adjusts for one-time items. [2] Based on financial data as of 09/30/2011.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Favourable long-term fundamentals support liquids pipelines

Business risk low but rising

Weak financial metrics

Organizational and financial complexity and structural subordination

Corporate Profile

Enbridge Inc. (ENB, Baa1 senior unsecured) is a North American pipeline and gas distribution utility holding company. ENB generates stable cash flows and has a low business risk profile due to its focus on energy businesses that are either regulated or supported by long-term contracts.

ENB's liquids pipelines segment (51% of 2010 net income as adjusted by ENB for non-recurring items (ENB-adjusted net income)) is anchored by the regulated Enbridge System, the Canadian portion of the mainline system that moves the bulk of the crude oil produced in Western Canada to the U.S. and Eastern Canada. Both the Enbridge System and ENB's regional oil sands pipelines have grown significantly in the last five years driven by expansion of oil sands production. We believe that strong supply/demand fundamentals will exist in ENB's liquids pipelines segment for the foreseeable future.

ENB's Gas Distribution segment (16% of ENB-adjusted net income) holds Enbridge Gas Distribution (EGD), Canada's largest regulated gas distribution utility. The Gas Pipelines, Processing and Energy Services segment (12% of adjusted income) is home to some of ENB's higher business risk operations such as Tidal Energy Marketing (ENB's trading and marketing operation), Enbridge Gas Services (manages ENB's merchant capacity on its gas pipelines) and ENB's investment in the Aux Sable gas processing facility. These higher risk businesses comprise a small component of ENB's overall operations (about 6% of adjusted income). This segment also holds ENB's interest in gas pipelines including Alliance US, Vector Pipeline and Enbridge Offshore Pipelines located in the Gulf of Mexico.

ENB's sponsored investment reporting segment (21% of ENB-adjusted net income) consists of ENB's partial ownership interests in Enbridge Energy Partners, L.P. (EEP, Baa2 senior unsecured) and Enbridge Income Fund (ENF, Baa2 senior unsecured) both of which are financing vehicles for liquids pipeline, gas pipeline, gas gathering and processing (G&P), and a portion of its renewable power assets. Under Canadian GAAP, ENB equity accounts for its 26% investment in EEP which understates the relative size and importance of EEP to ENB. EEP's principal asset is the regulated Lakehead System, the U.S. portion of ENB's liquids mainline. EEP also has meaningful G&P investments. ENB has a 69% economic interest in ENF whose three segments are its 50% share of the Canadian portion of the Alliance gas pipeline system, the Saskatchewan liquids pipeline system, and renewable power projects.

SUMMARY RATING RATIONALE

ENB's Baa1 senior unsecured rating is primarily driven by the preponderance of low-risk, rate-regulated pipeline and gas distribution assets which generate a predictable and growing cash flow stream. However, these attributes are offset by a relatively weak financial profile for ENB's rating. Over the last five years, ENB was in midst of the largest construction program in its history. Property plant & equipment have almost doubled due primarily to the growth of the liquids pipelines segment which is being driven by rising oil sands production. 2011 is significant in that it is the first year that major projects like the Alberta Clipper and Southern Lights, which together cost roughly $6 billion, will be in service for the whole year.

Capital spending is unlikely to abate in the next four years, as ENB undertakes a second wave of pipeline projects to serve not only the oil sands but also oil shale from the Bakken. With the exception of the proposed $5.5 billion Northern Gateway project, investments on the horizon are smaller than the marquee projects of the last few years and thus pose less execution risk and can be better absorbed by the company's now much larger asset base. This pace of investment, however, will keep ENB's cash flow credit metrics from materially improving, because of the continuing lag between the investment of capital and commencement of cash flow.

ENB's business risk is on the rise and will need to be offset by a strengthening of ENB's financial profile to avoid negative rating pressure. For example, its Canadian liquids line adopted tariffs this year that introduced sensitivity to throughput volumes. TransCanada's Keystone pipeline has brought new competition to ENB's liquids system. Management is also interested in expanding new business lines, such as renewable energy, G&P, and international, which are relatively minor now but riskier than ENB's core businesses.

The rating also reflects ENB's organizational and financial complexity and the structural subordination of ENB's senior unsecured debt due to the use of master limited partnership and income fund vehicles and non-recourse debt. Furthermore, we consider the MLP and income fund structures to be inherently riskier than corporate structures given the twin imperatives of distribution growth and distributing all cash flow in excess of sustaining capital which reduces financial flexibility and renders these vehicles more vulnerable to interruptions in capital market access.

DETAILED RATING CONSIDERATIONS

The primary rating methodology applied to ENB is our Natural Gas Pipelines methodology. Notwithstanding that the majority of ENB's pipelines are liquids rather than gas, we believe that the rating factors in the Natural Gas Pipeline methodology are equally applicable to ENB's regulated and/or contracted liquids pipelines. In addition, we also consider the Regulated Electric and Gas Utilities methodology recognizing that ENB's regulated gas distribution utility investments. EGD is ENB's largest gas distribution utility and accounts for about three quarters of the ENB-adjusted net income from gas distribution utilities.

FAVOURABLE LONG-TERM FUNDAMENTALS SUPPORT LIQUIDS PIPELINES

ENB's significant growth in recent years has been driven in large part by the growth of Alberta's oil sands and U.S. demand for secure supplies of energy. Despite widespread concerns about the environmental impacts of oil sands production, we believe that there will continue to be strong demand for oil sands production and therefore pipeline capacity through the long-term. Accordingly, we expect that the long-term fundamentals for ENB's largest business segment will be favourable for an extended period.

BUSINESS RISK LOW BUT RISING

We consider ENB's predominant pipeline and gas distribution utility operations, which together comprise the majority of its assets, to have low business risk because they are either regulated or supported by long-term contracts and have attractive long-term fundamentals. The pipeline assets tend to be regulated or supported by long-term take-or-pay contracts with creditworthy counterparties (regional oil sands pipelines, Alliance and Vector) which lends stability and predictability to the pipeline cash flows.

On July 1, 2011, the Competitive Tolling Settlement (CTS) came into effect for the Enbridge System. This new tolling scheme introduces potential revenue volatility to the System. Previously, the Canadian liquids pipelines operated under cost-of-service ratemaking, which provided throughput protection whereby revenue under-collections or over-collections due to fluctuations in throughput volumes were rolled forward for recovery or refund in the following year. Under CTS, revenues will depend on volumes and other variables.

EGD's business risk remains low given its utility monopoly status and lack of commodity price exposure. EGD covers a sizable franchise territory in Toronto which has proved resilient through the economic cycle, and it continues to add new customers at a steady pace. The company is operating under a five-year incentive regulation (IR) settlement which expires at the end of 2012. We expect that the rate methodology for the next five year term will be credit-neutral and consistent with Ontario Energy Board's well-established framework.

ENB engages in several business activities that we consider to be riskier than its pipeline and gas distribution activities. The largest of these is the gas G&P business at EEP which is exposed to varying degrees of commodity price and volume risk. While ENB hedges EEP's price and volume exposures to a significant degree, a portion of the business must always remain unhedged to allow for volume fluctuations which depend on many factors (drilling activity, decline rates, commodity prices etc.) that EEP cannot control. Furthermore, it is only economic to hedge a few years into the future therefore this business is unavoidably exposed to price risk as hedges expire. Additionally, ENB's gathering facilities in the Gulf of Mexico (Enbridge Offshore), Aux Sable and Energy Services activities are exposed to commodity price and volume risks.

Renewable energy activities, principally wind and solar electricity generation, are riskier than the pipeline and gas distribution businesses although less risky than gas G&P. While this is a small component of the company now, ENB plans to grow renewable energy into another business segment. Renewables tend to be uneconomic in the absence of government subsidies and therefore require legislative or regulatory support in order to be built. Furthermore, individual renewable projects are arguably dispensible unlike say ENB's mainline system without which the functioning of the North American economy would likely be significantly constrained.

WEAK FINANCIAL METRICS

ENB has a weak, though stable financial profile. ENB's weak financial profile is mitigated by the strategic importance of the mainline system which moves the majority of WCSB crude production to the U.S. and eastern Canada. To support ENB's ratings, the financial profile needs to be stronger going forward, as cash flow becomes more variable with the introduction of volume risk with CTS, introduction of competition from TransCanada's Keystone projects, and new investments in unregulated businesses.

Cash flow has increased from new projects that have come into service, but debt has also risen in tandem so that cash flow metrics have not improved significantly. The lag in cash flow from new investments will continue to weigh on ENB's credit metrics as the company keeps up its capital expenditures. Future improvement in credit metrics is deterred by the company's plan to rely on debt, rather than equity, for external financing of the next wave of projects. Consequently, ENB's funds flow from operations (FFO)/Debt is expected to be sustainable in the 11% to 13% range and FFO Interest Cover in the mid-3x range.

ORGANIZATIONAL AND FINANCIAL COMPLEXITY AND STRUCTURAL SUBORDINATION

ENB's use of MLP/Income Fund vehicles to control key infrastructure assets and its use of non-recourse debt creates a degree of complexity in ENB's organization and financing structure. We consider this to be a relative weakness in that it obscures economic reality and creates structural subordination. The roughly $4 billion of long-term debt at the ENB level as of September 30, 2011 is structurally subordinate to approximately $14 billion of long-term debt at the subsidiary/sponsored investment level including EGD, Enbridge Pipelines, ENF and Alliance Pipeline as well as EEP.

Notwithstanding that EEP is critical to ENB by virtue of its ownership of the Lakehead System and that EEP has no employees and is operated by ENB, ENB has not been required to consolidate EEP under Canadian GAAP. We believe that equity accounting for EEP significantly understates the degree of interrelatedness between ENB and EEP and EEP's importance to ENB. Beginning in January 2012, ENB will adopt US GAAP and consolidate EEP. Based on September 2011 balance sheet, EEP would increase ENB's consolidated debt by roughly $4 billion from debt reported under Canadian GAAP.

We also note that, all else being equal, the execution and financing risks are higher for an MLP than a corporation because of the MLP's high payout ratio and consequent higher reliance on access to the capital markets for both equity and debt funding. This has been the case for EEP in recent years and has resulted in ENB providing significant financial support to EEP in the form of periodic equity injections, inter-corporate credit facilities and arrangements to fund portions of capital projects (Alberta Clipper).

Liquidity Profile

We believe that ENB's committed liquidity is adequate.

ENB generated FFO of about $2.5 billion during the last four quarters ending September 30, 2011. Combined with cash on the balance sheet at September 30, 2011 of $0.6 billion, ENB will have cash resources of roughly $3 billion. After dividends of approximately $0.9 billion, capital expenditures of about $4 billion and scheduled debt maturities of about $0.3 billion, we estimate that ENB will have a funding requirement of roughly $2 billion for the four quarters ending December 31, 2012.

As of September 30, 2011, ENB had approximately $6.5 billion of authorized credit under various committed revolving credit facilities both at the holding company level and at subsidiaries. This figure excludes the credit facilities at EEP since ENB does not consolidate EEP. We calculate that availability under these facilities was roughly $3.8 billion at September 30, 2011, an amount sufficiently in excess of ENB's estimated funding requirement for the four quarters ending December 31, 2012.

Rating Outlook

The rating outlook is stable reflecting our expectation that ENB's business risk profile will remain relatively low, and that ENB's funds flow from operations (FFO)/Debt is sustained in the 11% to 13% range and FFO Interest Cover, in the mid 3x range.

What Could Change the Rating - Up

ENB's rating would likely be upgraded if the company could demonstrate that there is likely to be a improvement in key cash flow metrics such as FFO/Debt above 15% and FFO Interest Coverage above 3.8x on a sustainable basis.

What Could Change the Rating - Down

ENB would likely be downgraded if there were a deterioration in both its business risk profile and its cash flow credit metrics. For instance, a material increase in exposure to the riskier G&P segment or FFO/Debt sustained below 10% and FFO Interest Coverage, in the low 3x range would likely result in a downgrade.

Rating Factors

Enbridge Inc.

Natural Gas Pipelines [1]	[2]**Current LTM**		[3]**Moody's 12-18 Month Forward View As of 11/18/2011**	
Factor 1: Market Position (20.0%)	**Measure**	**Score**	**Measure**	**Score**
a) Market Position		Aa		Aa
Factor 2: Quality of Supply Sources (20.0%)				
a) Quality of Supply Sources		Aa		Aa
Factor 3: Contract Quality (20.0%)				
a) Contract Quality		Baa		Baa
Factor 4: Financial Strength (40.0%)				
a) (FFO + Interest Expense) / Interest Expense (3 Year Avg)	4.2x	A	3.0-4.0x	Baa
b) FFO / Debt (3 Year Avg)	16.00%	Baa	11.5-13%	Ba
c) Debt / Book Capitalization (3 Year Avg)	58.40%	Ba	58-63%	Ba
d) Operating Margin (3 Year Avg)	8.80%	B	8-12%	B
Rating:				
a) Indicated Rating from Grid		Baa1		Baa1
b) Actual Rating Assigned		Baa1		Baa1

[1] All ratios are calculated in accordance with Moody's Natural Gas Pipelines Methodology. In addition, Moody's adjusts for one-time items. [2] Based on financial data as of 09/30/2011. [3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures

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OMERS Administration Corp.

Major Rating Factors

Issuer Credit Rating

AAA/Stable/A-1+

Strengths:

- A very strong net asset position that a comprehensive risk management framework protects
- Mandatory participation of Ontario municipalities, local boards (including nonteaching staff only of school boards), and their employees
- Long-term investment performance that continues to exceed benchmarks

Weaknesses:

- Challenging economic and demographic trends in recent years, resulting in recurring funding deficits

Rationale

The ratings on OMERS Administration Corp. (OMERS or the fund) reflect Standard & Poor's view of a very strong net asset base; continued participation of Ontario municipalities, local boards, including school boards (nonteaching staff only), and their employees; and solid long-term investment performance that continues to exceed benchmarks. We believe the challenging economic and demographic trends of recent years, which have resulted in recurring funding deficits, offset these strengths somewhat.

OMERS' primary plan net asset position and liquidity levels remain very strong, in our view. As of Dec. 31, 2011, net assets available for benefits were C$55.0 billion, up from C$53.3 billion a year earlier. Annual benefit payments in 2011 were C$2.4 billion--contributions (including additional voluntary contributions [AVCs]) totaled C$2.8 billion, and the fund held about C$6.1 billion in cash and liquid short-term deposits to ensure it had sufficient liquidity. Furthermore, a well-established, comprehensive enterprise risk management framework protects OMERS' financial strength. We believe that the fund will maintain this strength.

Continued participation in the fund is required for Ontario local governments and local boards, including school boards (nonteaching staff only) and their employees, with very rare exceptions. The credit quality of Ontario municipalities, who have been the largest member group historically, has been very strong. We believe the solid credit quality of OMERS' employers and the fund's multiemployer nature will continue to provide a stable, highly predictable contributor base with stable associated cash inflows from their pension contributions.

OMERS' investment performances have exceeded its benchmarks. For 2011, the overall rate of return of 3.17% on the primary plan exceeded the benchmark of 2.52%; in 2010, its primary plan return of 12.01% surpassed the 11.47% benchmark. Similarly, the return in the past 10 years of 6.43% exceeded the 10-year benchmark of 5.91%. We expect that the fund's investment strategy and active asset management will continue generating investment returns that exceed benchmarks.

Along with other pension funds, OMERS has faced problematic economic and demographic trends in recent years.

Longevity has increased steadily in the past decade. Furthermore, the ratio of workers to retirees has been declining in Canada as a result of increasing life expectancy and other demographic factors. In 2011, there were 2.2 active members per pensioner--a number we expect to gradually decline. Despite investment returns that have often exceeded actuarially required rates of return over the last ten years and recent contribution rate increases, OMERS recorded a primary plan funding deficit of C$7.3 billion at the end of 2011 and an market value deficit of C$9.6 billion as a result of these trends. The fund has taken steps to address these shortfalls, including contribution rate increases in 2011, 2012 and 2013 and benefit reductions for people who leave the plan after 2012.

In 2004, OMERS began to implement a strategy of shifting a greater share of its assets to private markets from public to reduce the volatility of returns. We will continue to monitor the strategy's implementation and how the fund manages increased private market investment within its overall risk management framework.

Outlook

The stable outlook reflects Standard & Poor's expectation that OMERS will continue increasing its strong net asset position and maintain its very strong liquidity levels in the next two years. We expect that the underlying credit quality of the fund's contributor base will remain solid and that pension contribution inflows will be stable. Furthermore, we expect that OMERS will implement its shift to private markets and that investment performances will meet or exceed benchmarks. A change in risk-acceptance leading to a more aggressive investment stance and large investment losses, a dramatic rise in deficits (funding or market value), or a significant change in the sponsors' (and province's) commitment to the fund could exert downward pressure on the ratings during our two-year outlook horizon.

"Moderately High" Likelihood Of Extraordinary Support

In accordance with our government-related entity criteria, we view the likelihood of OMERS receiving extraordinary government support as "moderately high," based on our assessment of its "important" role in providing pensions to employees of Ontario school boards (nonteaching staff only), as well as municipalities and other local boards. We believe that the fund has a "strong" link with the province, as the province's previous status as plan sponsor demonstrates.

OMERS Is One Of Canada's Largest Pension Plans

At Dec. 31, 2011, OMERS managed primary plan net assets of C$55.0 billion, which was up from C$53.3 billion a year earlier. It had 419,007 members, of which 263,059 were active and 118,310 were retired (or survivors). This translates to about 2.2 active members per pensioner. Including AVCs, the plan paid out about C$2.4 billion in benefits to members and took in contributions of about C$2.8 billion.

The OMERS plan is a contributory, defined benefit pension plan funded by equal contributions from employees and employers and the plan's investment earnings. OMERS has 947 participating employers across the Province of Ontario (AA-/Negative/A-1+).

Continued participation in the plan is mandatory for designated employers and their full-time employees with very few exceptions. The plan's multiemployer nature provides some diversification on the contribution side. We believe Ontario's municipalities generally have strong credit quality due to their strong liquidity levels, moderate debt burdens, and growing local economies.

Recent strategic initiatives

In addition to the asset mix policy to shift exposure from public markets to private markets, starting in 2007 OMERS launched four major initiatives: accessing domestic capital through OMERS Investment Management (OIM); accessing foreign capital through Global Strategic Investment Alliance (GSIA); establishing strategic investment opportunities through OMERS Strategic Investments (OSI); and implementing direct-drive active management of investments.

At the end of 2011, OMERS managed more than C$800 million on behalf of third parties and about C$100 million in AVCs from fund members. The fund seeks to expand its fund-management activities beyond its traditional membership. The province has granted OMERS broad powers to manage third-party capital pools, including the assets of government funds, Canadian registered charities, any registered pension fund or endowment fund (based in Canada or otherwise). Rather than building significant marginal capacity to accommodate the additional clientele, OIM intends primarily to leverage asset-management resources already in place. Agreements with OIM clients will be structured as derivatives transactions, giving the client the total OMERS return or the return specific to one of its infrastructure, real estate, or private equity portfolios.

The GSIA intends to match OMERS with long-term co-investment partners globally, particularly for large-scale investments in real estate and infrastructure. GSIA partners would examine new opportunities together, according to an agreed set of principles, as opposed to ad hoc partnerships for particular deals. GSIA announced its first close in April 2012 that will commit US$5.00 billion from OMERS and US$1.25 billion from each of two other funds.

OSI is a subsidiary with a mandate to develop strategic co-investment relationships and alliances to forge proprietary investment opportunities and to create a portfolio of strategic investment platforms to the benefit of all OMERS investment entities--particularly Oxford Properties Group, Borealis Infrastructure, and OMERS Private Equity. OSI has investments in the areas of commodities, technology, and emerging markets.

OMERS has indicated that it wants to increase direct active management of its investments to 90% by 2015--it managed about 70% of investments in 2008. It wants to move away from its traditional approach of investing in private equity primarily as a limited partner in externally managed private equity funds, and toward actively managing the majority of its private equity investments. At year-end 2011, 84% of assets were under direct management, which was down (temporarily) from 86% a year earlier.

Pension Fund Sponsorship And Governance

OMERS is a multi-employer pension plan established and maintained pursuant to the Ontario Municipal Employees Retirement System Act, 2006, and is subject to provincial pension regulation. OMERS is the continuation of the previous Ontario Municipal Employees Retirement Board (pre-2006) and continues to be the administrator of OMERS' pension plans and trustee of the pension funds, the body that establishes its investment policies and invests the fund's assets.

Under the act, the plan will remain a defined benefit pension plan, equally funded by employers and plan members. The fund's assets are separate from those of the province and each employer.

OMERS Sponsors Corp. is the plan's sponsor replacing the Ontario government as the plan's sponsor. It is responsible for determining plan design and setting contribution rates as well as establishing a reserve to stabilize contribution rates. Contributions cannot be reduced nor benefits enhanced under the plan unless there is a 5% funding reserve and no funding solvency deficiency. The corporation consists of a board of 14 directors made up of employer and plan member representatives.

Actuarial Valuation Is In Deficit

In Ontario, pension plans must file a funding valuation with the regulator at least every three years and review the contribution rates and benefits, which may be adjusted depending on the plan's funding status. OMERS performs an independent actuarial valuation every year.

At the end of 2011, the plan had had a market value deficit of C$9.6 billion (funding deficit of C$7.3 billion), which increased from C$6.7 billion a year earlier. This came despite a modest increase in net assets as the accrued pension obligation rose on accrued interest on the benefit obligation, an increase in net accrued benefits (benefits accrued less benefits paid), and experience losses.

The outlook for a material improvement in the funding deficit in the next two years is not favorable. Previous investment losses are smoothed in actuarial valuations; the fund has net losses of about C$2.3 billion remaining that it will recognize in the actuarial value of net assets during the next four years.

The widening of the funding deficit in 2011 (see charts 1 and 2) came despite a sponsors corporation decision in 2010 to increase contribution rates temporarily for both employers and employees, on average by 1.0% in 2011, 1.0% in 2012, and 0.9% in 2013. The sponsors also decided on a small, temporary decrease to benefits for members who terminate their employment before early retirement eligibility. The benefit adjustment will apply only to individuals who leave the plan after 2012. These measures should eliminate the deficit in the next 15 years, if investment return assumptions hold. If investment returns fall short or the accrued pension benefit increases faster than expected, further contribution rate increases or benefit adjustments might be necessary.

Chart 1

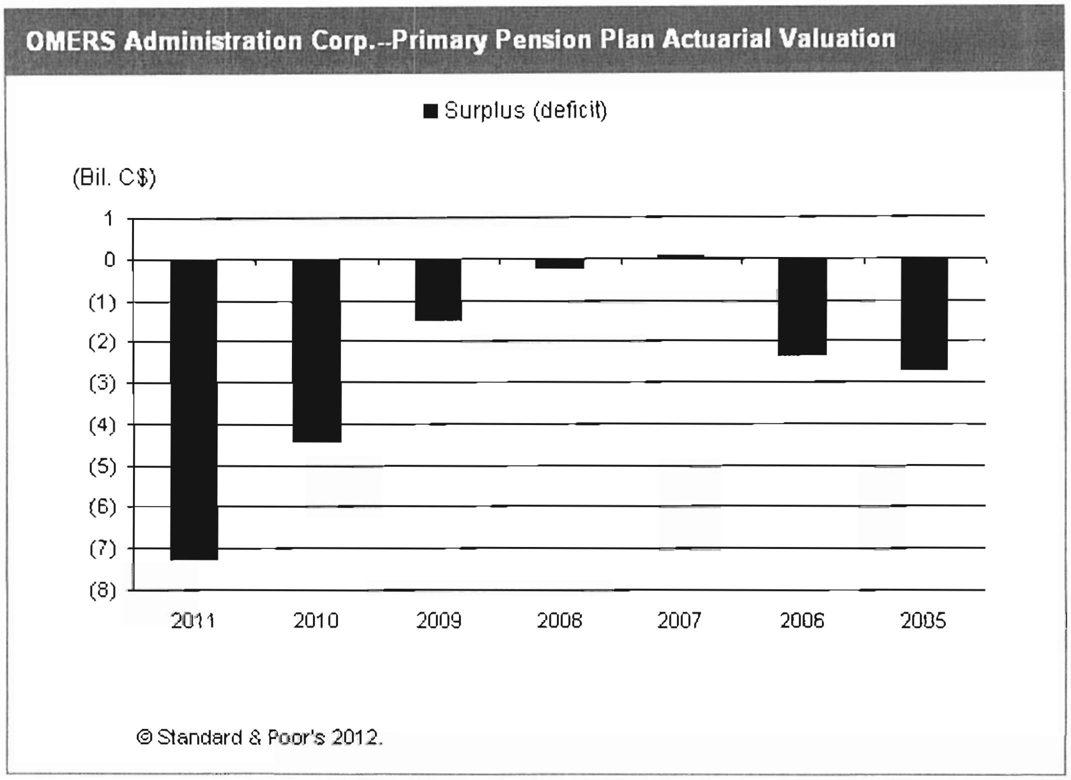
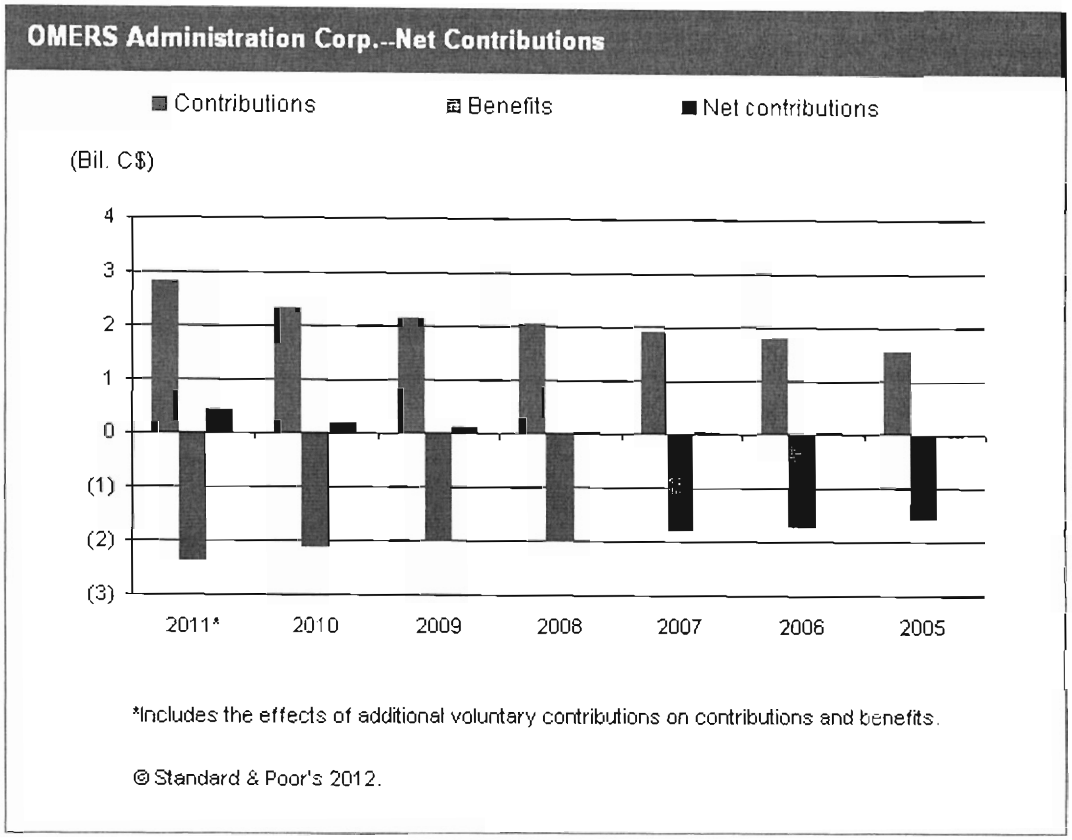

OMERS Administration Corp.--Primary Pension Plan Actuarial Valuation
Surplus (deficit)
(Bil. C$)
1
0
(1)
(2)
(3)
(4)
(5)
(6)
(7)
(8)
2011
2010
2009
2008
2007
2006
2005
© Standard & Poor's 2012.

Chart 2



OMERS's benefits include all standard pension plan entitlements (normal retirement, death, and disability benefits). The fund calculates pensions using a benefit formula designed to integrate with the pension payable from the Canada Pension Plan. The normal retirement pension is calculated using a member's years of credited service and the average annual pensionable earnings during the member's highest 60 consecutive months of earnings. Retired members have guaranteed inflation protection up to 100% of the cost-of-living allowance increase with a 6% annual cap, including a roll-forward of any excess.

Asset Allocation Strategy

In choosing investments that meet its risk and reward criteria, OMERS follows what we consider a disciplined investment process, with investment policies and procedures for each asset class. The fund's short-term goal is to add value above the returns of the markets in which it invests. Its long-term goal is to exceed the funding requirement of 4.25% plus the rate of inflation (CPI). Each portfolio's performance is measured against a benchmark that sets the standard for each investment entity. Management and the OMERS board review and approve these benchmarks in addition to the risk-management policy review.

OMERS conducts daily measurements of investment performance relative to corresponding program benchmarks for marketable securities; for nonmarketable securities, it records income monthly and conducts a valuation exercise at least annually. All policies and procedures are well-documented, in our view.

OMERS has been reducing its exposure to public markets, shifting to private markets, for a number of years. In 2003, market exposure was 82%; at the end of 2011, its public market exposure stood at 58%. The fund's private market investments consist of private equity, infrastructure, and real estate. The goal is to decrease public market holdings to 53%, increasing private markets to 47%, in an effort to continue to earn strong, but more stable, long-term returns. We do not expect this to change the fund's liquidity profile materially, because substantial amounts will still be in highly liquid assets. The long-term asset-mix goal is the most important factor in the board's investment policy. Asset mix is reported daily, allowing senior management to react quickly to deviations from the stated policy.

The long-term asset mix goal is the cornerstone of OMERS's investment policy. The right asset mix, combined with active management helps meet the pension plan's long-term return requirements with a targeted risk level.

As a share of total assets at Dec. 31, 2011, the public market asset exposure was 29% interest bearing (22% at the end of 2010), 25% public equity (37%), and 4% real return bonds (3%). At that time, the private market exposure was 14% private equity (12% at the end of 2010), 15% infrastructure (14%), and 13% real estate (12%).

OMERS AC undertakes a comprehensive asset-liability review every three years, with the board approving recommendations. Periodic reviews happen in the interim, using valuation projection models.

Overall Return Exceeds Benchmark: Investment Entity Results Are Mixed

The fund's overall rate of return exceeded the benchmarks in both 2010 and 2011. For 2011, the overall rate of return of 3.17% on the primary plan exceeded the benchmark of 2.52%; in 2010, its primary plan return of 12.01% surpassed the 11.47% benchmark. Similarly, the return in the past 10 years of 6.43% exceeded the 10-year benchmark of 5.91%.

The performances relative to benchmarks of individual investment entities, however, were mixed in 2011 (see table), not surprisingly. The top three performers relative to benchmark were OMERS Private Equity (7.2% return in 2011 versus negative 5.6% for the benchmark); Borealis infrastructure (8.8% versus 8.0%) and Oxford Property Group (8.4% versus 6.8%). OMERS Capital Markets, on the other hand, underperformed the benchmarks--Canadian public equities, international public equities, and real return bonds underperformed their benchmarks. Real return bonds and interest-bearing investments generated the highest rates of return. The lowest rates came from Canadian public equities and international public equities.

The investment return performances in 2010 were much different. Only OMERS Private Equity underperformed the benchmarks; but at 22%, it also had the highest rate of return. In OMERS Capital Markets, the highest rates of return were from Canadian public equities, and real return bonds.

OMERS Administration Corp.--Investment Entity Performances

(%)	2011 return	2011 benchmark return	2010 return	2010 benchmark return	2009 return	2009 benchmark return
OMERS Capital Markets	(0.2)	1.3	11.0	10.1	11.0	13.5

OMERS Administration Corp.--Investment Entity Performances (cont.)						
Interest-bearing	9.1	9.2	6.7	6.4	4.2	5.2
Real return bonds	17.8	18.4	11.0	11.1	14.3	14.5
Canadian equity	(11.3)	(8.7)	18.3	17.6	34.0	35.1
Non-Canadian equity	(5.0)	(4.2)	9.9	8.0	7.3	14.2
OMERS Private Equity	7.2	(5.6)	22.2	28.1	13.9	6.7
Oxford Properties Group	8.4	6.8	7.5	6.7	1.3	6.7
Borealis Infrastructure	8.8	8.0	10.1	8.5	10.9	9.0
OMERS Strategic Investments	7.2	6.9	7.7	7.0	(1.2)	10.7
Total plan	3.2	2.5	12.0	11.5	10.6	12.1

Well-Established And Comprehensive Risk Management Framework

To spread risk and reduce the variability of returns, OMERS diversifies its investments by investment type, style, country, industry, and duration. The board's investment committee also sets out and monitors policies on derivatives, interest-rate risk, stock market risk, foreign currency-asset risk, liquidity risk, and credit risk.

We view OMERS's risk management framework as adequate, although short of best practice.

We regard the following as key strengths of the framework:

- It includes staff dedicated to risk management functions.
- Dedicated staff produces regular reports detailing risk measures.
- The board of directors reviews risk reports regularly.
- Major risk categories are addressed (for instance, market, liquidity, credit, operational, and legal).

Notable shortcomings with the framework, in our opinion, include:

- The relatively small number of centralized dedicated staff;
- The dispersion of such staff across several teams, with various areas of responsibility and supervisors; and
- The lack of independence of dedicated staff from those with responsibility for financial reporting or making investment decisions.

Debt

Changes to the Pension Benefits Act, which took effect Jan. 1, 2001, gave OMERS and other pension funds the opportunity to provide a loan, incur debts, or provide other financial assistance to a wholly-owned subsidiary, so long as the subsidiary is in compliance with the Federal Investment Regulations, and is following the prudent person rule.

As a result, in 2002, OMERS provided its wholly owned real estate subsidiary, OMERS Realty Corp. (ORC), with an unconditional and irrevocable guarantee to support its debenture-issuance activities. Oxford Properties Group Inc., another subsidiary of OMERS, manages ORC, which has several long-term debentures outstanding, ranging in maturity from 2012 -2018. In 2010, OMERS provided a similar unconditional and irrevocable guarantee to OMERS Finance

Trust (OFT; 'A-1+' short-term rating), a newly-created subsidiary of OMERS, to support its short-term (commercial paper) borrowing on behalf of OMERS.

As of Dec. 31, 2011, ORC's guaranteed debt stood at C$1.45 billion, which was unchanged from 2010. OFT's guaranteed debt stood at about C$1.8 billion, down close to C$900 million from 2010. Total OMERS guarantees amounted to C$3.7 billion and represented only about 6% of net assets (about 8% in 2010).

The fund's board has the power and authority to extend this type of guarantee. Standard & Poor's has received a legal opinion that indicates that the claims against OMERS pursuant to these guarantees enjoy a payment priority over the claims of the OMERS plan's members; as a result, should the plan wind up, the claims pursuant to these guarantees would be entitled to be repaid out of the assets of the pension fund in priority to distributions to the plan's members.

Related Criteria And Research

- Public Finance Criteria: Public Pension Funds, June 27, 2007
- Rating Government-Related Entities: Methodology And Assumptions, Dec. 9, 2010

Ratings Detail (As Of July 20, 2012)	
OMERS Administration Corp.	
Issuer Credit Rating	AAA/Stable/A-1+
Commercial Paper	
Local Currency	A-1+
Senior Unsecured	AAA
Issuer Credit Ratings History	
26-Jul-2004	AAA/Stable/A-1+
14-Nov-2002	AAA/Stable/--

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 3 to UCT

On Page 60, UCT states that Florida Power and Light has a "customer service reliability which was 99.98% in 2012". How is this derived? For example, is this a customer survey or an industry recognized index?

Response:

The customer service reliability number was derived from an industry recognized index, the System Average Interruption Duration Index (SAIDI) defined in IEEE Standard 1336-2012, IEEE Guide for Electric Power Distribution Reliability Indices. SAIDI is an industry recognized standard that indicates the total duration of interruption for the average customer during a predefined period of time. The reported 2012 Adjusted SAIDI[1] for FPL is 65.8 minutes a year. The total number of minutes in a year is 60*24*365 = 525,600 minutes. This gives us the following calculation:

1 – [65.8 Minutes (Adjusted SAIDI for FPL 2012) / 525,600 (minutes in a year)] = 99.9875%

Thus, 99.98% is the double-digit accuracy truncated percentage representing the percentage of the year in which the average FPL customer experienced no interruptions in service based on an Adjusted SAIDI.

[1] Adjusted SAIDI allows the utility to remove outages/interruptions due to "Named Hurricanes," planned service interruptions, etc. IEEE 1336-2012 states: "It is recommended that the identification and processing of catastrophic events for reliability purposes should be determined on an individual company basis by regulators and utilities since no objective method has been devised that can be applied universally to achieve acceptable results. A major event designates an event that exceeds reasonable design and or operational limits of the electric power system." [see Florida Administrative Code 25-6.0455 Section 4 below for full list of exclusions]

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 4 to UCT

NextBridge's tower design proposes the use of 16 km spacing for dead end towers to limit cascading. Please explain whether this spacing conforms to good utility practice and is otherwise prudent given the potential for extreme weather conditions across this part of northern Ontario.

Response:

ASCE Manual 74, "Guidelines for Electrical Transmission Line Structural Loading", Section 3.3.2 states "cascading failure risk of a transmission line can be reduced by several methods." These methods are 1) design of all structures for longitudinal load, 2) installing failure containment structures, or 3) installing release mechanisms. Cascade failure containment will be evaluated in more detail during detailed design of the facilities. NextBridge included the cost of these deadends as a way to capture the cost of whichever anti-cascade strategy proved to be most effective.

NextBridge believes that 16 km spacing between deadend towers is consistent with good utility practice. The use and spacing of these structures is addressed in the ASCE Manual 74.

Section 3.3.2.2 of the manual discusses the use of failure containment structures for lines with H-frames, stating that there is "no hard and fast rule for the interval between failure containment structures, but intervals of up to 10 miles [16 kilometres] are common."

The manual further states:

> "H-frames <u>and narrow-based, rectangular, latticed structures</u> (which) have little inherent ability to withstand the longitudinal loads of a cascading line." [Emphasis added]

The structures proposed by NextBridge are neither H-frames nor narrow-based, rectangular, latticed structures. NextBridge is proposing a Guyed-Y structure. ASCE Manual 74 states, in Section 3.3.2.1:

> "Rigid square-based lattice towers, longitudinally Guyed-Y structures…are capable of resisting longitudinal loads and providing failure containment at a relatively low cost."

NextBridge's proposed Guyed-Y structure will have 4 guys with a longitudinal offset that inherently provide support of longitudinal loads.

On this basis, NextBridge's internal experts are of the view that the proposed 16 km spacing for deadend towers is consistent with good utility practice.

NextBridge also notes that the existing HONI East-West Tie has much greater than 16km intervals between deadend towers with no evidence of an extensive cascade failure. According to outage data provided by HONI, in 2009, there was an ice storm that caused damage to the Marathon-Lake Head line, which took 16 days to restore. The NextBridge team, in one of its field visits to the project, saw evidence of 9-10 structures that were replaced in the recent past. There were no deadends observed in this impacted segment of the line. This real life example demonstrates that failures can be contained without deadends. As the ASCE Manual 74 states, a rigid square-based lattice tower, or longitudinally Guyed-Y structure can resist the longitudinal loads generated by the initiating event.

During detailed engineering, NextBridge will review the design methods provided in ASCE Manual 74, and the additional security measures suggested in CAN/CSA-C22.3 No. 60826-10, Section 6.6.3.3 related to residual static load to confirm the appropriate method for failure containment.

UPPER CANADA TRANSMISSION, INC.

**Response to Board Interrogatory 5
to UCT**

Are the tower clearances shown at Tab 6, page 90, in conformance with the prescribed galloping requirements in the Board's Minimum Technical Requirements? If so, please explain.

Response:

Yes, single loop galloping analysis was performed with the tower configuration shown and no phase-to-phase contact was observed. Any minor adjustments, if needed to meet OEB specified phase-to-phase clearances for galloping, will be identified during final design.

UPPER CANADA TRANSMISSION, INC.

**Response to Board Interrogatory 6
to UCT**

What limitations does a compact design of 6m between phases pose on the ability of workers to complete maintenance on live lines?

Response:

NextBridge sees no inherent issues regarding live line maintenance with the configuration proposed using 6m phase spacing. NextBridge will meet all of the project minimum technical requirements, including provisions for performing live line maintenance of the facilities. Specific work methods and practices for live line maintenance of the East-West Tie line will be incorporated into the Operations and Maintenance plan for the project.

NextBridge affiliate Florida Power and Light (FPL) has decades of experience with live line maintenance at 230kV and 500kV voltage levels, and in design of structures, work methods and procedures to accommodate live line maintenance. FPL has live line maintenance practices for 230kV double circuit structures with less than 6m phase spacing.

During detailed design, an “electrical window” around the phase conductors will be established to maintain the safe work distances necessary for live line maintenance. These clearances will become critical design requirements for the final structure designs developed by the selected tower vendor.

Please see also NextBridge response to Board interrogatory 18 to all applicants.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 7 to UCT

Indicate whether, and if so where, the time to apply for and obtain pre-construction permits is taken into account in UCT's schedule.

Response:

NextBridge has taken into account the time required to apply for and obtain pre-construction permits in its schedule. Nextbridge outlines its detailed project execution schedule in Appendix 15 of its Application – Nextbridge Project Execution Chart. This schedule outlines the time periods allocated to developing, applying for and receiving approval for all pre-construction permits.

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 8 to UCT

Please advise whether the reference at page 9 of the Introduction to alternative forecasts for construction costs purported to offer construction cost reductions ranging between 25% to 30% are the same alternatives evaluated in Appendix 11 of UCT's application.

Response:

The 25% to 30% savings referenced on page 9 of the Introduction are not related to the estimates provided in Appendix 11.

The 25% to 30% cost reduction is the difference between Hydro One's 2010 $600 million cost estimate[2] and NextBridge's estimated total cost of $430 million for the Reference Plan and $397 million for the Recommended Plan, adjusted to account for differences in scope, specifically the removal of substations. This calculation is reflected in the following table:

	Reference Plan ($ MM)	Recommended Plan ($ MM)
NextBridge Development	$22.40	$22.40
NextBridge Construction	$430.00	$397.00
NextBridge Total	$452.40	$419.40
HONI Comparable Scope	$600.00	$600.00
NextBridge cost relative to HONI	75.4%	69.9%
Cost Reduction Percentage	24.6%	30.1%

The alternatives evaluated by PTerra in Appendix 11 are conceptual and were used to rank a wide range of options from a technical and cost perspective. NextBridge

[2] Line and Station, Capital & MFA cost of the Hydro One L1 option (OSHW) - Hydro One AR 18379 – Project Definition Report, Study Estimates for Options, East-West Tie Expansion, June 4, 2010, page 38 and 39.

completed this analysis to reduce the initial set of options to those warranting further consideration and analysis.

UPPER CANADA TRANSMISSION, INC.

**Response to Board Interrogatory 9
to UCT**

UCT has proposed that it may be appropriate to consider a similar concept to the current OPA Feed-in-Tariff Program ‘First Nation and Métis Adder’. Please provide greater details about how such a program would work in the context of transmission of electricity. Please provide examples to illustrate the proposed concept.

Response:

In Appendix 5 of its Application, NextBridge has suggested a number of potential alternative approaches to provide for First Nation and Métis economic participation. We have suggested solutions to economic participation that we believe could be negotiated and administered in a transparent way, and be straightforward to implement. In some instances these potential solutions could enable First Nation and Métis communities to avoid having to borrow, or could offset any ongoing costs of borrowing, to make an equity investment.

One such suggestion is a First Nation and Métis Adder. The concept is similar to that of the OPA’s “First Nations and Métis Adder” as included in previous versions of the Feed-in-Tariff (FIT) Program. In the FIT example, an adder over the base FIT rate was paid to a provider scaled according to the percentage of ownership held by First Nation and Métis investors. For example, a large wind project receives $135.00/MWh for energy it produces. If First Nation or Métis investors have an “Economic Interest” (essentially an at risk value stream) valued at more than 50% of the project value of a wind development, an “adder” of $15.00/MWh is added to the energy rate paid to the project under its OPA off-take agreement, and the project participants can elect to allocate some or all of this adder to the First Nation or Métis participants.

Recognizing that the Provincial Government has expressed its interest in First Nation and Métis economic participation in transmission, the successful proponent in this proceeding could collect in approved transmission rates a premium amount over and above its otherwise determined revenue requirement. NextBridge would propose to allocate all of this premium amount entirely to First Nation and Métis participants. Such funds would constitute a cash flow that could be utilized directly by the First Nation and

Métis participants, or could be applied to offset debt service costs incurred on any funds borrowed for investment in the project by a First Nation or Métis group. NextBridge appreciates that this option is novel and would need to be proven to have an acceptable impact to ratepayers.

UPPER CANADA TRANSMISSION, INC.

**Response to Board Interrogatory 10
to UCT**

Please provide a forecast of the costs to ratepayers on an annual basis to fund a return on CWIP during the construction phase of UCT's planned East-West Tie line and compare this to the costs to ratepayers under the Board's standard rate making approach.

Response:

Under standard ratemaking, UCT would accrue AFUDC and include the accumulated balance in its opening rate base. The notional example below illustrates the effects of this treatment as compared to the earning of a return on CWIP prior to commercial operations. As can be seen in this example, the CWIP during construction totals $22.4 MM paid in cash compared to the AFUDC charge of $23.3 MM in additional rate base. For this illustration, we have used a 5.6% rate for carrying charges as reflected in the OEB Appendix A – Minimum Design Criteria for the Reference Option of the E-W Tie Line, November 9, 2011, page 5.

As the notional model indicates, the ultimate cost to ratepayers as shown through the present value of payments to investors, is equivalent. Given the same cost of capital and therefore the same carrying charge, earning a cash return on CWIP is the economic equivalent of accruing AFUDC on CWIP. It is simply a trade-off between early and smaller vs. later and bigger cash payments. From the customers' perspective, the principal disadvantage of a cash return on CWIP is that it requires them to start to pay in advance for future transmission service. The principal advantage is that it can facilitate raising cost-effective debt financing during the construction phase, owing to the early generation of cash flow. This potential benefit, which is not quantified in our example, would ultimately serve to lower customer rates. A secondary benefit of a cash return on CWIP during construction is the smoothing effect on customer bills. A third benefit is that it results in lower overall payments in total over the life of the asset, as less interest is capitalized and subject to a return.

NextBridge is not reliant on construction financing and therefore does not require a cash return on CWIP. However, we do think that a single-project, construction phase utility is a prime candidate for the application of this OEB-endorsed rate making tool, in that it has the potential to facilitate a more cost-effective construction phase financing than may otherwise be available to the project, ultimately reducing ratepayer costs. While this is our suggested approach, we would like to clarify that our proposal is not contingent on receiving a cash return on CWIP; we are equally prepared to move forward with AFUDC.

CWIP vs. AFUDC Comparison

Comparison of cost to ratepayers on an annual basis to fund cash return during construction compared to accrued AFUDC in rate base.

Assumptions

Carrying Charge	5.60%
Project life (years)	50

Ratepayer Payments Present Value

CWIP Return Example	$335.8
AFUDC Return Example	$335.8
Difference to Ratepayers	$0.0

(Discount Rate of 5.6%)

Notes:

Carrying charge per AFUDC rate stated in OEB Appendix A - Minimum Design Criteria, November 9, 2011, page 5

Construction cost estimate of $377.5 MM as shown in Response to Board Interrogatory 26, Total 2012 Dollars, unescalated

Annual amounts shown are totaled from monthly calculations

For this example, no additional capital is spent after COD in 2017

CWIP Return ($ MM)						
Year	Capital Invested	CWIP Charge / Payment	End of Year Rate Base	Return on Capital	Return of Capital	Ratepayer Payments
2015	26.4	0.7	26.4			0.7
2016	179.1	5.7	205.5			5.7
2017	172.0	16.0	377.5			16.0
2018			369.9	20.9	7.5	28.5
2019			362.4	20.5	7.5	28.1
2020			354.8	20.1	7.5	27.7
2021			347.3	19.7	7.5	27.2
2022			339.7	19.3	7.5	26.8
2023			332.2	18.8	7.5	26.4
2024			324.6	18.4	7.5	26.0
2025			317.1	18.0	7.5	25.5
2026			309.5	17.6	7.5	25.1
2027			302.0	17.1	7.5	24.7
2028			294.4	16.7	7.5	24.3
2029			286.9	16.3	7.5	23.8
2030			279.3	15.9	7.5	23.4
2031			271.8	15.4	7.5	23.0
2032			264.2	15.0	7.5	22.6
2033			256.7	14.6	7.5	22.2
2034			249.1	14.2	7.5	21.7
2035			241.6	13.8	7.5	21.3
2036			234.0	13.3	7.5	20.9
2037			226.5	12.9	7.5	20.5
2038			218.9	12.5	7.5	20.0
2039			211.4	12.1	7.5	19.6
2040			203.8	11.6	7.5	19.2
2041			196.3	11.2	7.5	18.8
2042			188.7	10.8	7.5	18.3
2043			181.2	10.4	7.5	17.9
2044			173.6	10.0	7.5	17.5
2045			166.1	9.5	7.5	17.1
2046			158.5	9.1	7.5	16.7
2047			151.0	8.7	7.5	16.2
2048			143.4	8.3	7.5	15.8
2049			135.9	7.8	7.5	15.4
2050			128.3	7.4	7.5	15.0
2051			120.8	7.0	7.5	14.5
2052			113.2	6.6	7.5	14.1
2053			105.7	6.1	7.5	13.7
2054			98.1	5.7	7.5	13.3
2055			90.6	5.3	7.5	12.9
2056			83.0	4.9	7.5	12.4
2057			75.5	4.5	7.5	12.0
2058			67.9	4.0	7.5	11.6
2059			60.4	3.6	7.5	11.2
2060			52.8	3.2	7.5	10.7
2061			45.3	2.8	7.5	10.3
2062			37.7	2.3	7.5	9.9
2063			30.2	1.9	7.5	9.5
2064			22.6	1.5	7.5	9.0
2065			15.1	1.1	7.5	8.6
2066			7.5	0.7	7.5	8.2
2067			0.0	0.2	7.5	7.8
Total Payments		**22.4**				**929.3**

AFUDC Return ($ MM)						
Year	Capital Invested	AFUDC Accrual	End of Year Rate Base	Return on Capital	Return of Capital	Ratepayer Payments
2015	26.4	0.7	27.2			0.0
2016	179.1	5.9	212.1			0.0
2017	172.0	16.7	400.8			0.0
2018			392.8	22.2	8.0	30.3
2019			384.8	21.8	8.0	29.8
2020			376.8	21.3	8.0	29.4
2021			368.8	20.9	8.0	28.9
2022			360.8	20.4	8.0	28.5
2023			352.7	20.0	8.0	28.0
2024			344.7	19.5	8.0	27.6
2025			336.7	19.1	8.0	27.1
2026			328.7	18.6	8.0	26.7
2027			320.7	18.2	8.0	26.2
2028			312.7	17.8	8.0	25.8
2029			304.6	17.3	8.0	25.3
2030			296.6	16.9	8.0	24.9
2031			288.6	16.4	8.0	24.4
2032			280.6	16.0	8.0	24.0
2033			272.6	15.5	8.0	23.5
2034			264.6	15.1	8.0	23.1
2035			256.5	14.6	8.0	22.6
2036			248.5	14.2	8.0	22.2
2037			240.5	13.7	8.0	21.7
2038			232.5	13.3	8.0	21.3
2039			224.5	12.8	8.0	20.8
2040			216.5	12.4	8.0	20.4
2041			208.4	11.9	8.0	19.9
2042			200.4	11.5	8.0	19.5
2043			192.4	11.0	8.0	19.0
2044			184.4	10.6	8.0	18.6
2045			176.4	10.1	8.0	18.1
2046			168.4	9.7	8.0	17.7
2047			160.3	9.2	8.0	17.2
2048			152.3	8.8	8.0	16.8
2049			144.3	8.3	8.0	16.3
2050			136.3	7.9	8.0	15.9
2051			128.3	7.4	8.0	15.4
2052			120.3	7.0	8.0	15.0
2053			112.2	6.5	8.0	14.5
2054			104.2	6.1	8.0	14.1
2055			96.2	5.6	8.0	13.6
2056			88.2	5.2	8.0	13.2
2057			80.2	4.7	8.0	12.7
2058			72.2	4.3	8.0	12.3
2059			64.1	3.8	8.0	11.9
2060			56.1	3.4	8.0	11.4
2061			48.1	2.9	8.0	11.0
2062			40.1	2.5	8.0	10.5
2063			32.1	2.0	8.0	10.1
2064			24.1	1.6	8.0	9.6
2065			16.0	1.1	8.0	9.2
2066			8.0	0.7	8.0	8.7
2067			0.0	0.2	8.0	8.3
Total Payments		**23.3**				**962.9**

UPPER CANADA TRANSMISSION, INC.

Response to Board Interrogatory 11 to UCT

UCT indicates in section 5.8 of the application:

"…Nextbridge also intends to develop with its Ontario stakeholders a performance-based ratemaking construct. This construct could be viewed as a form of project-specific return on equity incentive, in line with the OEB's Infrastructure Investment Policy."

Please confirm that under whatever performance-based rate making construct UCT ultimately proposes:

a) UCT would seek a rate of return on common equity ("ROE") of 10 percent, if the total project capital cost is less than the budgeted capital cost; and

b) UCT would seek an ROE of 9 percent if the total capital cost of the project exceeds the budgeted capital cost.

Response:

Figure 9 of Section 5.4 of the NextBridge Application was provided for illustrative purposes only, to demonstrate that a a significant decrease in capital expenditures in exchange for a modest increase in ROE can provide an attractive value proposition for customers. Round numbers were used in the example, with the "Case 1" ROE of 9% being representative of the standard Board approved ROE (currently 8.93%), and 10% illustrating a premium over and above the standard Board approved ROE if superior performance is achieved, to illustrate that the ratepayer is better off in "Case 2".

As noted in Section 5.4 of the Application, with respect to the Cost of Equity, NextBridge would seek to develop a ratemaking construct that would be acceptable to the Board while allowing NextBridge to achieve a higher rate of return in exchange for assumption of risk and/or superior performance. This is similar to the current incentive rate making opportunities afforded to Ontario electricity and gas distributors, which have allowed for the sharing of earnings above Board approved ROE between utility owners and utility ratepayers. NextBridge expects that the range of potential ROE outcomes, together with appropriate metrics, would be developed in consultation with OEB staff and other stakeholders.