



Feasibility Study - Transmission Lines Action Plan.



New Hampshire Office of Energy and Planning
Prepared by KEMA, Inc.
Burlington, MA, October 1, 2010

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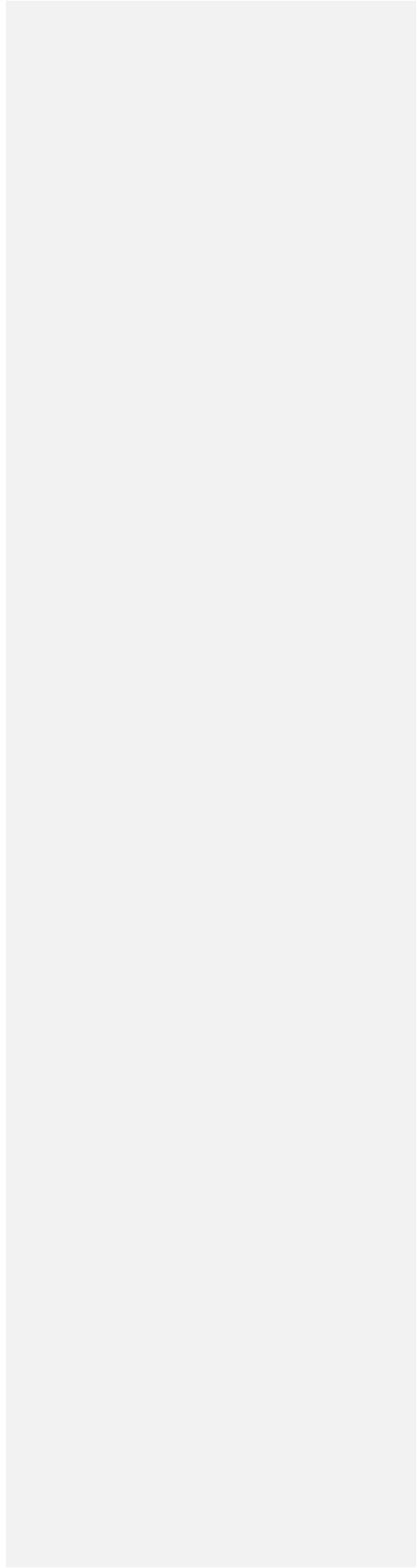




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1. Executive Summary

1.1 Problem Description

Northern New Hampshire is rich in renewable energy resources. However, the existing transmission infrastructure in the region is not sufficient for integrating all of the proposed renewable generation projects. Transmission investments would be needed to interconnect resources, address ensuing reliability needs and ensure enough capacity so that generators have transmission access to transmit the full power they are capable of producing.¹

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Investments to integrate proposed renewable energy projects in northern New Hampshire could cost many millions of dollars. Under existing regulations, the costs of upgrades to the local transmission system, known as the “Coos Loop”, would be the responsibility of generators wishing to interconnect.² Such integration costs vary by generator, depending on location and on the extent of prior upgrades made by other interconnecting parties. In some cases, the interconnection costs, in conjunction with other project risks that affect financing, may be too great to justify the investment. Larger transmission investments to integrate numerous renewable resources on a regional basis are also possible. However, under current rules, the costs for such investments must be borne by participants if the investments do not provide reliability or market efficiency benefits to New England.

Coordination among the interested parties could facilitate commitments that could be made to reduce project risks and to clarify how investors would recover their costs. As such, in order to enable transmission developments that would integrate renewable resources in northern New Hampshire, a consensus agreement is needed on how to allocate transmission costs beyond the methods specified in existing regulations. This report lays out the framework for an action plan to pay for an upgrade of the transmission system in northern New Hampshire, otherwise

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¹ Limited capacity on the line could mean that though generators might interconnect, they all would not be able to generate simultaneously at full output without violating ISO-NE's reliability rules. As such, designing the system for 'full deliverability' or the ability for all generators to generate simultaneously is important for generators to make sure they can sell 100% of their product.

² Existing regulations allow for certain transmission costs to be socialized across New England, where New England as a whole would realize reliability or market efficiency benefits from the upgrades. Upgrades to the Coos Loop would likely not qualify as reliability or market efficiency upgrades, under present regulations.

known as the North Country.³ It strongly recommends a cost allocation approach which entails a purchase power agreement between the State of New Hampshire and renewable energy developers to repay an up-front loan by the State. This study also identifies existing impediments to transmission development in northern New Hampshire, documents stakeholder concerns, and evaluates a series of cost allocation approaches used throughout the country.

1.2 Study Approach

In developing the framework of an action plan, consultants met with a number of stakeholders through private and public meetings and obtained information in the public record. Researchers obtained feedback from interested parties regarding potential cost allocation methodologies and the potential impact that transmission development and various cost allocation methods might have on stakeholders. As well as gathering input from stakeholders, researchers assessed whether cost allocation methodologies used throughout the U.S. would be applicable and beneficial to addressing transmission development barriers in the North Country. Researchers then proposed a subset of transmission cost allocation approaches and assessed the potential impact of these on stakeholders within New Hampshire. In completing the study, researchers developed a framework of an action plan, outlining implementation steps and recommending responsible parties. As requested by the study sponsors, the framework was based on the assumption that the transmission upgrades to integrate an additional 400 megawatts (MW) of new generation on the Coos Loop would cost \$150 million. As a sensitivity, researchers examined how cost allocation might change if upgrades were ten or twenty percent above or below this amount.

The following highlights the steps taken to develop the framework of an action plan to pay for a transmission system upgrade in New Hampshire's North Country:

1. **Meet with Stakeholders.** This entailed holding public and private meeting with a variety of interested parties to gather input.
2. **Recommend cost allocation methodologies and a financial framework appropriate for the Coos Loop.** This entailed summarizing how similar situations have been

³ Recommendations in this study may need to be tailored to meet both energy conservation or generation and historic preservation goals, or may need to be tailored if a project is using federal funding. Recommendations made in this Feasibility Study, if and when implemented, may require review by the New Hampshire State Historic Preservation Office.

handled across the country and looking at Federal changes in legislation that may affect cost allocation. The team also reviewed the challenges and opportunities of transmission cost allocation and proposed a subset of cost allocation solutions feasible for New Hampshire.

3. **Describe the potential cost impact of various cost allocation methodologies.** This entailed reviewing existing financial studies and analyses and assessing the impact of cost allocation methodologies on New Hampshire electricity customers, renewable energy generators and other parties.
4. **Develop the framework of an action plan.** This entailed identifying high-potential cost allocation solutions and defining steps to be taken to implement those solutions.

1.3 Findings

Under existing New England rules, socializing transmission investment costs across ratepayers is permissible only when the investment benefits the regional electric grid's reliability (ie upgrades to PTF facilities) or enhances market efficiency. In addition, the ISO New England, Inc., Transmission, Markets and Services Tariff ("ISO-NE Tariff") requires that all interconnection costs required to interconnect a generator including any necessary system upgrades are to be paid for solely by the generator.⁴ Given the nature of the Coos Loop facilities (non-PTF), that is, its limited interconnection with the New England electric grid, it is unlikely that upgrades to the existing system would result in regional reliability or market efficiency benefits, and thus do not qualify for regional rate recovery. Reliability upgrades required to serve local area load would be socialized across the entire Northeast Utilities system per its local tariff. New generator related upgrades can not be socialized per the ISO-NE Tariff. Even if the Coos loop was considered regional facilities (PTF) , the ISO-NE Tariff would require the costs to be paid for by the connecting generators. Therefore, transmission investments to upgrade the Coos Loop to accommodate additional generation , would need to be allocated outside of the ISO NE Tariff rules through independent agreement(s), if the current methodology was not acceptable. Alternatively, the ISO Tariff would need to be modified. However, this is a lengthy process requiring regional consensus and one which would modify the ISO Tariff rules governing transmission investments for the region as a whole. In the near term, innovative

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⁴ See ISO-NE Tariff at Section II (the "ISO-NE Open Access Transmission Tariff" or "ISO OATT"), Schedules 22 ("Large Generator Interconnection Procedures" or "LGIP") and 23 ("Small Generator Interconnection Procedures" or "SGIP").



Though region-wide planning is beyond the direct scope of this study, such planning is important as it could help to identify economically efficient ways to integrate larger quantities of renewable resources, and avoid incremental investments that can come at a higher cost per unit of capacity connected. There is a need, however, to balance such regionally optimized development with practical considerations to move forward quickly. In assessing the potential for regional solutions, it would be prudent to assess the total amount of developable renewable energy capacity that transmission development could support. A simple approach would be to provide a timeline over which interested parties could register their interest.

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Apart from New Hampshire-based efforts to develop transmission connecting remote renewable resources in Coos County to the grid, regional transmission development efforts are also under way. In particular, certain New England transmission operators are currently investigating a voluntary, “beneficiary pays” approach to connect more than 1,000 MW of remote, new renewable generation in New England. To date, the transmission owners have had preliminary discussions with regulators and developers regarding this high-level transmission plan.

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Several options within that plan are being considered, though there is not yet any formal proposal. As such, it is difficult to ascertain the initiative’s impact on New Hampshire or on efforts to upgrade transmission in the State’s North Country. Nevertheless, it appears highly probable that the regional effort, if consummated, could connect some or all of the renewable resources planned for northern New Hampshire. Therefore, depending on the regional initiative’s transmission design and on its ability to move forward, the regional project could affect the need to upgrade the Coos Loop to interconnect additional North Country renewable resources.

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Where the regional initiative’s design affects upgrades in the North Country, it potentially also affects the State’s role in supporting transmission development in the North Country. In particular, in the beneficiary pays approach being considered under the regional initiative, the purchasers of power, rather than the State or New Hampshire ratepayers, would ultimately pay for the transmission through a transmission service agreement associated with a purchase power agreement (PPA).⁷ In addition, where the regional initiative’s design addresses the

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⁷ Specifically, if approved by FERC and states, Renewable Developers would be granted access to, and the purchasers of power would pay for, transmission service from the transmission providers in order to make a related transmission and renewable generation product available to load in southern New England. The entities who enter into PPAs with Renewable Developers would effectively fund the

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majority need of renewable developers in the North Country, it could potentially supersede the need to develop a cost allocation plan specific to transmission development in Northern New Hampshire alone. As such, the regional initiative currently underway potentially presents another option should the State be unwilling or unable to finance or subsidize transmission development in the North Country. However, the lack of deadlines associated with the regional initiative, and the uncertainty in the transmission design, means that there is a tradeoff between waiting to assess potential synergies between a regional transmission development solution versus moving forward now to control the timeline and design of transmission development in New Hampshire's North Country.

The figure below summarizes key findings from this study.

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transmission and generation development. The transmission developer would recoup costs over time with load paying for the transmission costs of the project, and the generators would recoup generation investment costs through the PPA. Meanwhile, the existence of a PPA would facilitate generation financing. The project is intended to minimize costs by essentially routing transmission to the most cost effective renewable generation, thus minimizing generator interconnection cost and is intended to result in combined transmission and renewable generation product deliverable to loads in southern New England in a cost effective manner.

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Key Findings

- Socializing localized transmission costs across all New England ratepayers is an unlikely prospect given both current New England rules and given the nature and design of the Coos Loop.
- Approaches which allocate costs to beneficiaries or which serve public policy purposes are more likely to succeed.
- This study recommends an approach that reduces developer risks through commitments by the State to purchase power and provide up-front financing or low-debt loans to help reduce developer risk. Repayment to the State would occur over time through reduced rates negotiated in advance with developers.
- Although the Federal Energy Regulatory Commission is currently considering changes to its transmission rules, it is unlikely that such amendments will have a direct near-term impact on the Coos County transmission development.
- Regional planning initiatives are currently underway. If successful, these initiatives could affect the need to upgrade the Coos Loop to interconnect additional North Country renewable resources.

2. Introduction

In 2008, the New Hampshire Legislature formed the North Country Transmission Commission (NCTC) and directed it to complete a study to develop an action plan that identifies potential methods for allocating transmission costs.⁸ To assist in that effort, the New Hampshire Office of Energy & Planning (OEP) and the NCTC have sponsored this study, paid for in its entirety by funding awarded through the American Recovery and Reinvestment Act of 2009 (ARRA).

This report summarizes stakeholder input about transmission development in northern New Hampshire, otherwise known as the North Country, evaluates several transmission cost allocation methodologies for their potential application in the North Country, and lays out a framework of an action plan to pay for transmission upgrades in the region. It is not intended to assess or develop potential transmission designs. Rather, it is intended to help guide stakeholders towards reaching a consensus decision on ways to allocate the cost of potential transmission development in the North Country.

The remainder of this section provides background on existing transmission in the North Country. Section 3 highlights stakeholder opinion about transmission development in the North Country and proposed transmission cost allocation methodologies. Section 4 outlines the basics of transmission cost allocation and provides examples of how other states and regions are approaching this issue. Section 5 evaluates the application to New Hampshire of several transmission cost allocation approaches. Section 6 assesses the impact that transmission costs and benefits might have on local stakeholders in northern New Hampshire. Section 7 lays out the framework for an action plan to pay for an upgrade of the transmission system in the North Country.

2.1 Project Background

Stimulating and facilitating the development of renewable energy resources is a regional priority for New England and a state priority for New Hampshire. Each of the New England states has implemented a number of programs to promote the development of renewable resources.⁹

⁸ Senate Bill 383, Chapter 348, Laws of New Hampshire, 2008.

⁹ According to the 2009 Governor's Blueprint Report: "Each of the New England states is seeking, through initiatives associated with various state laws, policies, and regional coordination, the aggressive



The State of New Hampshire currently promotes renewable energy development through mandated utility purchases of renewable energy under a renewable portfolio standard (RPS), as well as tax exemptions and incentives for wind, biomass and solar generators.¹⁰

The North Country, particularly Coos County, offers plentiful wind and wood fuel energy resources which have attracted the attention of generation developers. Currently, renewable energy developers have proposed over 400 MW of wind and biomass projects in the region. However, the existing transmission line in the region, known as the Coos Loop, cannot integrate all of these proposed projects without further investment. Such investments are necessary to reliably move power from renewable generators to load centers in the region.

In 2007, New Hampshire Governor John Lynch signed into law legislation that stated encouraging renewable energy development is in the public interest, and that:

“existing transmission infrastructure, particularly in the northern part of the state, will need to be upgraded or replaced or new transmission facilities will need to be built.”¹¹

Existing transmission in Northern New Hampshire, including the Coos Loop, is owned by Public Service Company of New Hampshire (PSNH). The Coos Loop are 115 kilovolt (kV) lines comprised of four segments which connect to the Whitefield substation owned by PSNH. This substation is connected to the Littleton and Woodstock substations owned by PSNH and the Moore substation owned by National Grid. The Coos Loop is located in the towns of Northumberland, Stark, Milan, Berlin, Gorham, Randolph, Whitefield, and Lancaster. Two additional towns, Kilkenny and Jefferson, are located inside this loop. Figure 1 displays the approximate boundaries of the Coos Loop, which connects the Whitefield, Berlin, and the Lost Nation Substations.

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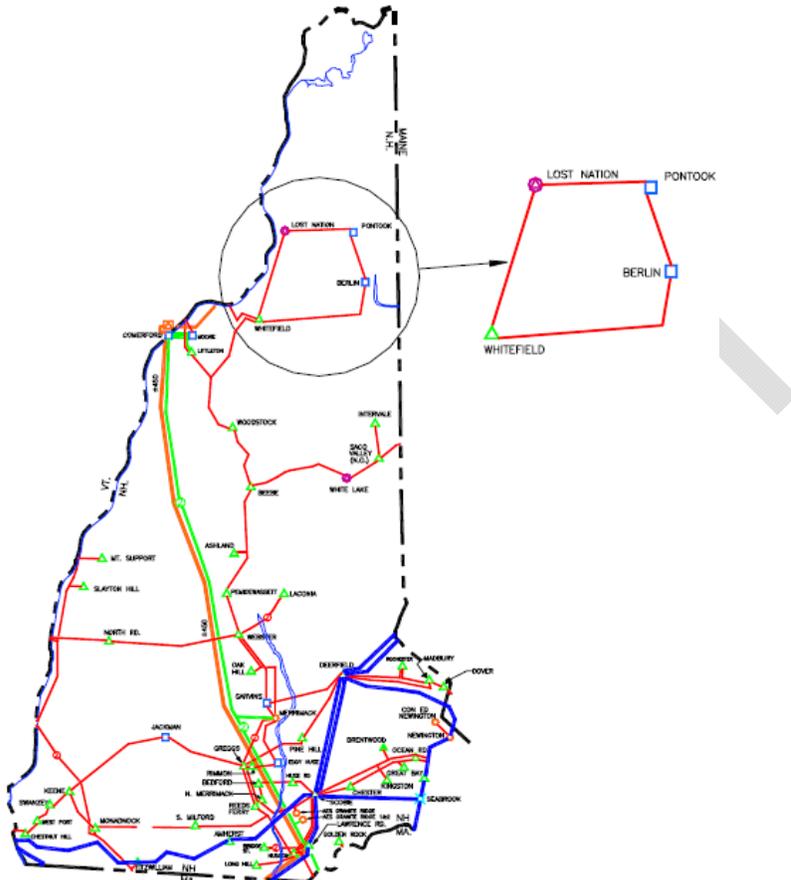
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development of renewable resource potential within and outside state borders.” (The New England Governor’s Conference, Inc 2009, Page 6).

¹⁰ NCSC and IREC, *New Hampshire Incentives/Policies for Renewables & Efficiency*. 2010.

¹¹ New Hampshire Laws of 2007, Chapter 364:1.

Figure 1. Coos Loop Transmission Line, Coos County, New Hampshire



Source: PSNH 2008.

2.2 Problem Description

Having full dispatch capability is the key to delivering power and is a primary factor in providing the certainty developers require to advance their projects. Other factors critical to financing include adequate market revenue to support the investment costs and ongoing fixed and variable costs. Developing transmission to interconnect potential renewable resources in the North Country could cost millions of dollars, and involve local, state, regional and national authorities.

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Under the existing ISO-NE Tariff rules, transmission costs are socialized, or distributed region-wide, if projects meet stringent system reliability or market efficiency criteria and the facilities are classified as network facilities (PTF). Because neither criterion likely applies, the proposed Coos County projects to date are all considered as being related to generation interconnections, and as such all necessary interconnection costs and related system upgrades, to connect new generation are borne by the generators. No specific transmission upgrade has yet been designed, as it depends on the amount and location of new renewable energy projects. However, PSNH has estimated that at least \$100 million could be required to connect 400 MW wind and biomass facilities to the Coos Loop.¹²

Historically, costs of transmission reliability projects have been allocated to and recovered from all ratepayers, while private generation project developers have paid to connect their facilities to the transmission grid. In the last decade, this model has come under review as states are seeking to remove economic barriers to encourage renewable development. Several renewable energy generators across the country, including Coos County, New Hampshire, have stated that the added cost of transmission upgrades can tip projects toward economic unfeasibility. States such as California, Texas, Oregon, Wyoming and many others have developed alternative approaches to creatively finance hundreds of millions of dollars in transmission upgrades needed to deliver power from generators to customers.

Various upgrades to the existing Coos Loop have been considered over a multi-year stakeholder process. However, thus far, no agreement has been reached on how the associated costs of upgrading the Coos Loop would be shared among parties. The issue of cost allocation so far has been an impediment to further transmission development in the region. To develop a workable solution, the New Hampshire Legislature mandated a study to develop an action plan and ways to allocate the proposed upgrade costs, and directed formation of the NCTC that brought stakeholders together.

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¹² PSNH, *Northern New Hampshire New Resource Interconnection Options and Costs*. 2008.

3. Stakeholder Roles, Feedback and Concerns

Throughout the study, researchers met with a number of stakeholders to solicit feedback and ascertain stakeholder's views on the impact that transmission development and various cost allocation methods could potentially have on stakeholders. This chapter describes the roles of several stakeholders interested in transmission development in the North Country and summarizes input received either through meetings or in the public record. This summary is not intended to represent a complete list of stakeholders or their comments. Rather, it is intended to be representative of the types of parties involved and the opinions voiced. Minutes from the public meeting held for this study and NCTC meetings regarding this study will become available on the New Hampshire Public Utility Commission's website.

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3.1 Stakeholders

A number of stakeholders with a diverse set of views have an interest in proposed transmission developments of the North Country. Stakeholders discussed here include State agencies and officials; representatives of the North Country; electric utility companies and transmission owners; transmission and generation developers; New England Independent System Operator (ISO-NE); and FERC.

3.1.1 North Country Transmission Commission

Created by the New Hampshire Legislature in 2008, the NCTC's purpose is to develop a plan for the expansion of the transmission capacity in the North Country.¹³ Members constitute a variety of stakeholders including legislative appointees as well as voting and non-voting members.¹⁴ The NCTC is administratively attached to the NHPUC.

¹³ Senate Bill 383, Chapter 348, Laws of New Hampshire, 2008.

¹⁴ Members of the NCTC include representatives from the State Senate and House of Representatives, New Hampshire Office of Energy and Planning, Energy Efficiency and Sustainable Energy Board, Public Utilities Commission, Governor's Office, North Country, Plymouth State University, Public Service of New Hampshire, National Grid Group, New England Power Generators Association, and organizations and associations associated with proposed renewable generation projects.



3.1.2 State Agencies and Officials

Office of the Governor. The New Hampshire Governor's Office has a long record of supporting energy efficiency and renewable energy development in the State. For example, in 2005, Governor John Lynch set a 10% reduction target for energy consumption in state buildings. Two entities oversee this effort, the State Energy Manager ensures that the Executive Order is fulfilled and the Department of Administrative Services (DAS) implements an energy information system to measure progress in meeting the 10% reduction target. OEP staff members support the State Energy Manger's efforts to collect and analyze data in State buildings. Currently, energy use per square foot in state owned buildings has decreased by 4% since 2005, although gross energy consumption in state-owned buildings has increased by 4%.¹⁵

In 2006, the Governor set a goal of having 25% of the state's energy requirements be met with renewable sources by 2025.¹⁶ In 2007, in close alignment with this goal, the Governor signed the Renewable Energy Act (HB 873) which sets a mandatory RPS for electricity providers.¹⁷ In 2009, to help meet New Hampshire's renewable energy goals, the State signed a \$4.4 million, 11-month electricity contract with ConEdison to purchase 25% of its energy from wind power.¹⁸

The electricity price is 9.2 cents / kWh for the generation component of the rate with other charges such as transmission, distribution, customer service, etc., making up the other component of the rate that are totaled on each customer's bill.¹⁹

More recently, in 2010, Governor Lynch signed into law SB73, which sets a goal that the State government reduces fossil fuel energy consumption per square foot in state-owned buildings by

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¹⁵ New Hampshire State Energy Manager. *State of New Hampshire Energy Management Annual Report for State-Owned Buildings and Fleets: Fiscal Year 2009*. 2009.

¹⁶ Accessible at: online at: http://www.nh.gov/oep/programs/25_x_25/index.htm. Accessed August 25, 2010. Energy requirements include transportation and heating energy and electricity generation.

¹⁷ New Hampshire Statutes, Chapter 362-F. The mandate requires electricity providers to obtain renewable energy certificates for 23.8% of the retail electric energy sold to end-use customers by 2025. Renewable energy certificates are records that identify each megawatt-hour generated by a renewable energy generating source under RSA 362-F:6. In 2008, amendments were enacted which exclude municipal suppliers from the requirements. (House Bill 295).

¹⁸ Accessible at: <http://www.governor.nh.gov/media/news/2009/070209.htm> Accessed August 25, 2010.

¹⁹ Estimated from contract dollar and energy amounts.

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25 percent by 2025.²⁰ Provisions of the law include requiring State government to reduce energy consumption in State buildings, to develop an energy conservation plan, and to report annually on the state's consumption. Today, the State government spends almost \$22.5 million on energy costs at over 1,200 buildings.²¹

The Governor's Office is also engaged in regional energy efforts. New Hampshire Governor Lynch joined with five other New England governors to adopt the *Renewable Energy Blueprint* on Sept. 15, 2009.²² This Blueprint expedites development of New England renewable energy by coordinating reviews of interstate transmission line project proposals. The states also will work together to coordinate solicitations and decisions on procuring power and long-term energy contracts.

The New Hampshire Office of Energy and Planning (OEP). The OEP is part of the Executive Department within the Office of the Governor. The agency supports and promotes numerous energy efficiency, renewable energy and other sustainability programs in the State. As a state agency, OEP is coordinating New Hampshire's energy programs funded through ARRA. This includes coordination of a competitive bidding process, consultant selection and oversight, and administration of the state's ARRA-funded grants. OEP staff members serve on the NCTC and oversee the administration of the contract to conduct the study for this report.

New Hampshire Public Utilities Commission (NHPUC). The NHPUC is a regulatory entity that has jurisdiction over utilities engaged in providing electric, telecommunications, natural gas, water and sewer services in the state of New Hampshire and whose authority covers rates, quality of service, finance, accounting and safety. Its stated mission is "to ensure that customers of regulated utilities receive safe, adequate and reliable service at just and reasonable rates."²³ The NHPUC has three Commissioners who are appointed by the Governor and confirmed by the Executive Council to staggered six year terms. A Chairman acts as the overall agency head. NHPUC staff members serve on the NCTC. The NHPUC's authority includes transmission-related issues and NHPUC staff members have been engaged in

²⁰ Senate Bill 73, Chapter 328, Laws of New Hampshire, 2010.

²¹ New Hampshire State Energy Manager. *State of New Hampshire Energy Management Annual Report for State-Owned Buildings and Fleets: Fiscal Year 2009*. 2009.

²² The New England Governor's Conference, Inc., *2009 New England Governors' Renewable Energy Blueprint*. 2009.

²³ Accessible at: <http://www.puc.state.nh.us/Home/aboutus.htm>. Accessed August 25, 2010.



transmission development in northern New Hampshire throughout. Previous reports drafted by NHPUC staff have provided information on transmission infrastructure and development in the State and examined possible cost allocation approaches.²⁴

Office of Consumer Advocate (OCA). The OCA represents the residential ratepayers in the State of New Hampshire and advocates on their behalf in accordance with State law.²⁵ The OCA is focused on residential customers of regulated utilities. While administratively attached to the NHPUC, the OCA is an independent organization and often a party at NHPUC cases.

Site Evaluation Committee (SEC). The SEC was created by the legislature to determine whether to grant generators the right to build a bulk power supply facility or other energy facility at a specific site.²⁶ In evaluating the application, the SEC must determine whether:

- *“the applicant has adequate financial, technical and managerial capabilities;*
- *the facility will not unduly interfere with the orderly development of the region;*
- *the facility will not have an unreasonable adverse effect on aesthetics, historic sites, air and water quality, the natural environment, and public health and safety; and*
- *the facility is consistent with state energy policy.”²⁷*

For approval of transmission lines over which the NHPUC has jurisdiction, the NHPUC must also find that the facility is “required to meet the present and future need for electricity” and that it “will not adversely affect system stability and reliability factors.”²⁸ The Committee has fourteen members from a variety of State agencies.²⁹

²⁴ NHPUC, *Background Report on New Hampshire Transmission Infrastructure*, 2007; NHPUC, *Commission to Develop a Plan for the Expansion of Transmission Capacity in the North Country: Progress Report. Pursuant to SB 383 Chapter 348, Laws of N.H.* 2008.

²⁵ RSA 363:28.

²⁶ A bulk power supply facility includes generating facilities capable of operating at 30 MW or greater and electric transmission lines rated at 100 kV over new rights of way and which are either associated with a generating facility or more than 10 miles.

²⁷ NHPUC, *Background Report on New Hampshire Transmission Infrastructure*, 2007.

²⁸ *Ibid.*

²⁹ Agencies represented on the Committee include the Department of Environmental Services, the Public Utilities Commission, the Department of Resources and Economic Development, the Department of



Legislators. The New Hampshire General Court, New Hampshire's state legislature, consists of 400 members in the House of Representatives and 24 members in the Senate. In 2007, the General Court concluded that "[i]t is in the public interest and to the benefit of New Hampshire to encourage the development of renewable energy" and that "the existing infrastructure, particularly in the northern part of the state, will need to be upgraded or replaced or new transmission facilities will need to be built." (Laws of 2007, Chapter 364:1). Related to this finding, the General Court directed the NHPUC to enable and facilitate stakeholder discussions and to submit a report describing the transmission system and the process and any alternatives to complete transmission upgrades

In 2008, the General Court established the NCTC to develop a plan for expansion of transmission capacity in the North Country.³⁰ In 2009, the legislature extended the NCTC through Senate Bill 85, which also directed the NCTC to hire a consultant to develop "a framework for a proposal for the upgrade of the transmission system in the North Country" to file with the FERC.³¹ This governmental agency oversees the transmission system reliability and the charges for transmission services.

In 2009, the members of the Senate and House sponsored legislation that would have appropriated \$155,000,000 to the public utilities commission to administer "capital improvements to the Coos Loop and other related transmission infrastructure in northern New Hampshire."³² The funds would come from a variety of sources, including new generation developers, New Hampshire ratepayers through a transmission charge, state-issued bonds and federally-funded programs.³³ The legislation did not make it out of the Senate Committee on Energy, Environment and Economic Development.

Health and Human Services, the Fish and Game Department, the Office of Energy and Planning, the Department of Cultural Resources and the Department of Transportation.

³⁰ New Hampshire Senate Bill 383. <http://www.gencourt.state.nh.us/legislation/2008/SB0383.html>

³¹ New Hampshire Office of Energy & Planning, *Request for Proposals Transmission Line Action Plan*, January 27, 2010.

³² NHPUC, *Background Report on New Hampshire Transmission Infrastructure*, 2007; New Hampshire Senate Bill 164, 2009.

³³ When SB 164 was first drafted, it appeared that American Recovery and Reinvestment Act funding would be available for transmission investments in remote areas that were rich in renewable energy resources. The final version of the bill, however, deleted those provisions.

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3.1.3 North Country Representatives

Economic Development Organizations. New Hampshire has a number of organizations throughout the State that support economic development within their communities or regions. These include Local Development Corporations, Regional Development Corporations, Certified Development Companies, and Industrial Development Corporations. These organizations support business development and economic growth within their communities and offer assistance through low-cost financing, among other services. The Coos Economic Development Corporation is part of a larger non-profit regional economic development corporation that serves the State of New Hampshire, and is a conduit for the U.S. Department of Housing and Urban Development community development block grants. In addition, the North Country Council is an Economic Development District as appointed by the U.S. Department of Commerce's Economic Development Administration. It covers 67 communities and 25 unincorporated places in New Hampshire.

Coos County Commission. The Coos County Commission consists of three Commissioners, Chair, Vice Chair and Clerk. The Commission serves as the executive branch of the County Government, and addresses fiscal and policy matters in the region. Coos County is one of ten counties in New Hampshire. Incorporated in 1803, Coos County has a population of about 33,000 people, and covers a land area of over 1,800 square miles, nearly 20% of the total land area of the State.³⁴

The General Public. Members of the public, including organizations and individuals residing or working in the State, provided input about the proposed developments in the North Country. Organizations included those serving the interests of the general public and local communities. The Coos Community Benefits Alliance (CCBA) is one such group. It is a group of like-minded organizations whose mission is to "ensure that energy projects in the Coos County region result in long-term, tangible benefits for local communities and our natural resource base."³⁵ Members include individuals from the New Hampshire Charitable Foundation, Bethel Local Energy Committee, Colebrook District Heating Committee, Tri-County Community Action Program, and the Northern Forest Center.

³⁴ Accessible at: <http://www.cooscountynh.us> and <http://quickfacts.census.gov/qfd/states/33000.html>. Accessed August 25, 2010.

³⁵ Coos Community Benefits Alliance, *CCBA Framing Document*. 2010.

3.1.4 Electric Utility Companies and Transmission Owners

Public Service Company of New Hampshire (PSNH). PSNH is the largest electric utility in the State, serving over 490,000 customers. (See PSNH's service area shown in Figure 2.) It is a wholly-owned subsidiary of Northeast Utilities, a utility holding company based in Connecticut. PSNH owns nine hydroelectric facilities, three fossil fuel-fired power plants which jointly constitute 1,110 MW of generating capacity. One of PSNH's fossil-fueled power plants also uses biomass as an input fuel. PSNH owns and operates approximately 1,000 circuit miles of high voltage transmission: 252 circuit miles at 345 kV, 743 circuit miles at 115 kV, and 8 circuit miles at 230 kV. This transmission system sends power through 56 substations across the State.³⁶

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National Grid (NGRID). NGRID is the other major transmission owning utility in New Hampshire. It serves over 38,000 customers. The utility owns and operates over 300 circuit-miles of transmission in New Hampshire. The majority of these transmission facilities, over 82%, are 230 kV lines, nearly 17% are 115 kV and less than 1% are 69kV. The 230 kV lines export power from the Comerford and Moore hydroelectric facilities on the Connecticut River to southern New England. The 115 kV lines supply local area loads.³⁷

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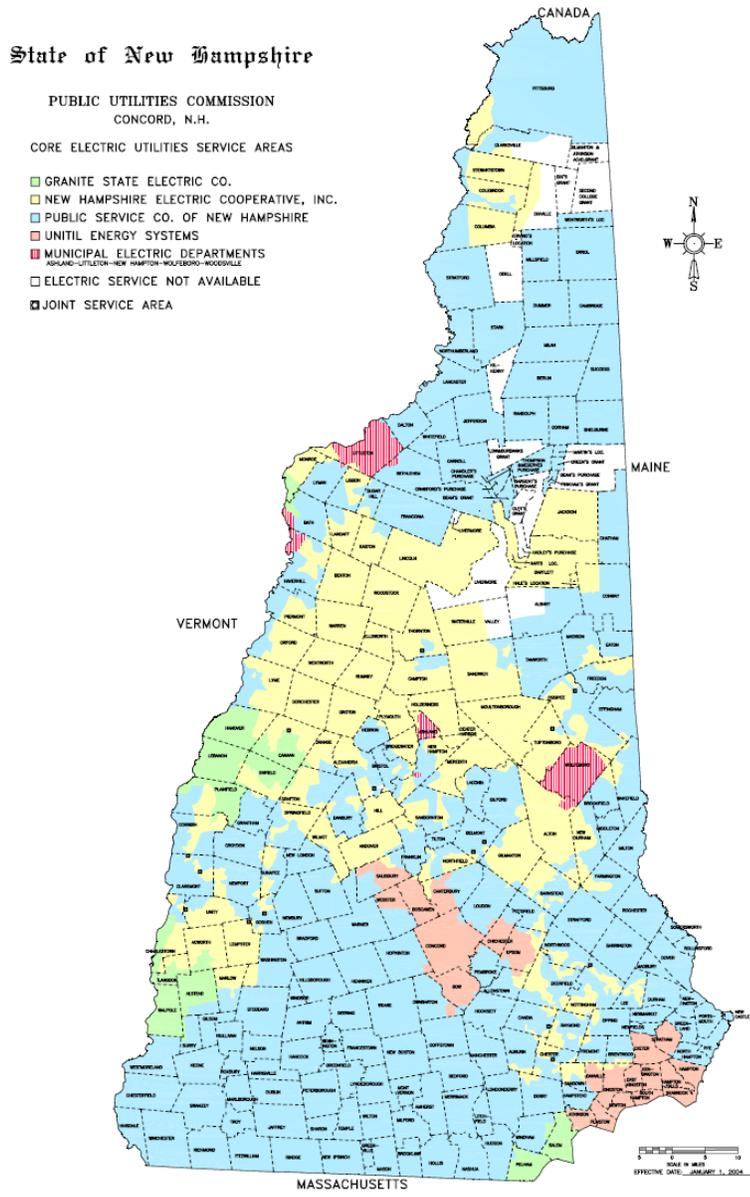
Anbaric Transmission. Anbaric Transmission develops, builds and owns independent transmission lines in the northeastern U.S. To date, it is the only non-utility entity that can develop transmission projects funded by ratepayers in New Hampshire. While Anbaric Transmission is an active stakeholder, to date no proposals have been submitted for private transmission in New Hampshire's North Country. The company has developed other transmission projects in the northeastern U.S. and is continuing to develop proposals.

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³⁶ NHPUC, *Background Report on New Hampshire Transmission Infrastructure*, 2007.

³⁷ Ibid.

Figure 2. Electric Utility Service Areas



3.1.5 ISO-NE

The Independent System Operator (ISO) of New England is a FERC-approved regional transmission organization (RTO) with operational control over transmission facilities throughout the six New England states, including New Hampshire. Rates, terms and conditions of transmission service in New England are set forth in the [ISO Tariff](#).³⁸ Rates and charges are regulated by FERC, and are subject to modification. Modifications may be made through a rate change filing by ISO-NE or a local transmission owner, as appropriate. Alternatively, a complaint filed at the FERC showing that existing rates, terms and conditions of service are unjust, unreasonable, or unduly discriminatory may result in a modification.

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The [ISO Tariff](#) allows for different cost allocations depending on whether a transmission facility is deemed a pool transmission facility (PTF) or a local transmission facility (LTF).

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- **Pool Transmission Facilities (PTF).** Generally, PTFs are transmission facilities that operate at 69 kV or above and that help to integrate region-wide electric system. The costs of PTFs are socialized and shared by transmission customers, [network load](#), throughout New England. [Network load pays for “Regional Network Service,” which is the revenue requirement for Pool Transmission Facilities. Generation that is connected to PTF does not pay for transmission service.](#)
- **Local Transmission Facilities (LTF).** LTF are transmission facilities that operate at lower voltages and generally function either as generation leads to deliver electricity from generation facilities to the grid, or to deliver electricity from the grid to serve local loads. The costs of LTF are paid by transmission customers of the local transmission owner, [which are both load and generation resources utilizing Non-PTF facilities](#). Where [a generation resource utilizes Non-PTF facilities to access PTF facilities to transmit generation, it pays for Local Transmission Facility use pursuant to Schedule 21 of the ISO Tariff.](#)

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3.1.5.1 Interconnection

Each generation interconnection project is unique and therefore, the administrative and technical studies (of feasibility, system impact, and facilities) necessary to determine the system

³⁸ ISO-New England, *ISO New England Transmission Market, and Services Tariff*. Retrieved from: <http://www.iso-ne.com/regulatory/tariff>

modifications required to ensure reliability must be conducted on a case-by-case basis. Throughout the process, ISO-NE must remain impartial while it administers the interconnection and facilitates communication between stakeholders. Each interconnection request is placed in a publicly available queue at the time the application is received. Where there may be an overlap in the impact of generators, the one that is filed first, and hence has a higher queue position, is given first rights to use the existing transmission. Today, there are over 100 projects active in the ISO-NE queue, including 1,200 MW of proposed new generation in New Hampshire. The northern New Hampshire renewable energy projects currently active ([this should be footnoted with a specific date](#), there are no longer 400 MW in the queue – only about 220MW with Northern wind withdrawing) in the queue total approximately 400 MW.

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Generator interconnections in New England are completed according to the FERC-approved Minimum Interconnection Standard (MIS).³⁹[\[this has changed, there are now several interconnection standards\]](#) The MIS is intended to promote access to the transmission system, but does not guarantee full deliverability of a generator's output. The Generator Interconnection Process (GIP) guides how, and under what conditions, new power plants are physically connected to the existing transmission system.⁴⁰ The [LGIA \(Large Generator Interconnection Agreement\)](#) applies to generators larger than 20 MW, and the [SGIA](#) applies to smaller generators.⁴¹ In terms of jurisdiction, the Coos Loop is FERC jurisdictional transmission, as would be any likely upgrades.

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Under ISO-NE's competitive wholesale electricity market structure, developers of generator projects are responsible for the costs of interconnection studies and any transmission upgrades that ISO-NE determines are necessary to allow a project to interconnect to the grid.

3.1.5.2 System Planning

Every year, ISO-NE works with transmission owners (TOs) in the region to develop a Regional System Plan (RSP).⁴² The annual RSP assesses system needs and identifies transmission

³⁹ NHPUC, *Background Report on New Hampshire Transmission Infrastructure*, 2007.

⁴⁰ Ibid.

⁴¹ Accessible at: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US06R&re=1&ee=1 [\[why not cite to the tariff?\]](#)

⁴² The Existing ISO New England Regional System Planning Process is described in Attachment K to the ISO New England Transmission, Markets and Services Tariff.



upgrades that would have regional benefits. Specifically, the RSP provides 10-year forecasts of consumption and peak demand, documents the adequacy of the region's bulk power system infrastructure, and reports on the ability of the region to comply with key policies such as the renewable portfolio standard. As part of the RSP process, ISO-NE reviews the reliability of designs proposed by TOs and reviews their transmission cost allocations to determine which costs should be regionalized versus localized.

There are several phases to the yearly process for transmission development. It begins with the identification of system needs, either in terms of generation or reliability, through various assessments. New England stakeholders then provide input to the RSP through the Planning Advisory Committee (PAC). The regional system planning process is open and iterative and culminates with an open meeting where the public can provide input to ISO's Board of Directors before the ISO approves the RSP. While the RSP seeks to address system needs with market responses, such as demand-side measures or merchant transmission, the RSP does not constitute an integrated resource plan. Regional cost sharing applies to transmission projects that benefit the entire region.

The RSP process has resulted in numerous transmission investments to maintain reliability, with \$4 billion worth of investment going into service since 2002 and about \$5 billion worth of further transmission projects planned.

3.1.6 Transmission and Generation Developers

A core group of stakeholders that develop wind and biomass generation and transmission have expressed an interest to build in the Coos County region if sufficient transmission capacity can be secured in a way that does not impair the economics of their projects. Several stakeholders have an economic interest in the Coos Loop upgrade to interconnect their proposed generation, while at least one stakeholder has expressed interest in developing the transmission upgrade if economically viable. [\(this is a bit misleading, PSNH and NGRID has always been ready to build the required system upgrades as long as an agreement can be reached with the generators requiring the upgrades or other parties willing to pay the costs\)](#) While other generation and transmission firms may have interests in such upgrades, the following firms have attended public meetings, participated in the NCTC and some have commenced project development in the North Country, as noted.

Laidlaw Energy Group (Laidlaw). Laidlaw, founded in 2002, develops, acquires, and converts existing generation facilities to biomass and solar energy facilities. Under its affiliates, the company acquires fossil fuel and idled plants, as well as idled pulp and paper mills, in the

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northeastern U.S. Affiliate Laidlaw Berlin BioPower, LLC acquired the Berlin-based former Fraser Paper Mill in 2008 and plans to convert and upgrade it to a 65 MW wood-fired biomass facility when required approvals are received. This plant will deliver hot water to a Gorham, N.H. paper mill, and electricity to PSNH under a long-term Power Purchase Agreement (PPA).⁴³ Laidlaw, based in New York, New York, is a publicly traded company (OTC: LLEG.PK) since 2002.⁴⁴

Clean Power Development (CPD). CPD develops wood-fired biomass facilities across the U.S. in connection with partner Gestamp Biomass, a division of Gestamp Renewables. Existing projects under development include a 29 MW biomass combined heat and power plant in Berlin, NH, expected to start construction in the fall of 2010, and a biomass power plant in Winchester, NH.⁴⁵

Noble Environmental Power (Noble). Noble, founded in 2004, is a private renewable energy generating company with a 726 MW generation portfolio and approximately 1,800 MW of windparks under development throughout the U.S.⁴⁶ Noble is majority-owned by JPMorgan Partners Fund, which is managed by CCMP Capital. The firm's Granite Reliable Wind Park, a 99 MW, 33-turbine wind farm, is currently under development. This farm is located in four Unincorporated Places — Dixville, Millsfield, Irvings Location, and Odell — as well as in the town of Dummer, all of which are in Coos County. This wind farm has signed agreements to sell more than half the wind power output. The project received a U.S. Army Corps of Engineer permit to go forward in June 2010.

Wagner Forest Management (Wagner Forest). Wagner Forest, headquartered in Lyme, employs more than 70 individuals, including roughly 40 foresters, and manages 2.7 million acres in the northeastern U.S. and eastern Canada. The firm has proposed a \$500 million, 200 MW wind power park in Dixville, New Hampshire.⁴⁷

⁴³ Accessible at: <http://www.laidlawenergy.com/berlin-nh-project.html>. Accessed September 28, 2010.

⁴⁴ Accessible at: <http://www.laidlawenergy.com/investors.html>

⁴⁵ Accessible at: <http://www.cleanpowerdevelopment.us/projects.php>

⁴⁶ Accessible at: <http://www.noblepower.com/about-us/index.html>

⁴⁷ Accessible at: <http://www.wagnerforest.com>

3.1.7 Federal Energy Regulatory Commission (FERC)

Transmission of electric energy in interstate commerce is regulated by FERC. By law, FERC is authorized to regulate the transmission and wholesale sales of electricity, and is charged with ensuring that rates, terms and conditions for wholesale sales and transmission of electricity in interstate commerce are just and reasonable and not unduly discriminatory or preferential. As such, FERC has authority over tariffs which allocate transmission costs among ratepayers in the region.

In 1996, FERC issued its Order No. 888, which requires all transmission owners to provide transmission service to all eligible customers on a non-discriminatory basis pursuant to a tariff on file at the FERC. In 1999, FERC issued its Order No. 2000, which encouraged utilities to transfer operational control over their transmission facilities to an independent RTO or ISO, which would provide transmission service on a region-wide basis.

Today, FERC has approved a number of tariffs which encompass a number of transmission cost allocation approaches. Section 4 provides a summary of some of these approaches. Generally, FERC is open to innovative transmission cost allocation, to the extent that it is just and reasonable.

On June 17, 2010, FERC issued a notice of proposed rulemaking (NOPR).⁴⁸ In the NOPR, FERC makes a preliminary finding that some existing methods for allocating the costs of new transmission may not be just and reasonable because they may inhibit the development of efficient, cost-effective transmission facilities necessary to produce just and reasonable rates. As such, FERC proposes transmission planning reforms, including a requirement that each transmission provider participate in a regional transmission planning process that produces a regional transmission plan. Information about ISO-NE's planning process is summarized in Section 3.1.5.

In its recent NOPR, FERC considers new rules that would address transmission development related to public policy initiatives. In particular, in addition to evaluating proposed transmission enhancements based on considerations of reliability and overall cost reduction, transmission providers would be required to consider transmission projects proposed to facilitate compliance with public policy requirements established by state or federal laws or regulations, such as

⁴⁸ FERC Docket Number RM10-23-000: Transmission Planning and Cost Allocation. June 17, 2010.

RPSs. Transmission providers are to identify specific public policy requirements established by state or federal laws or regulations to be considered in the transmission planning process after consultation with transmission customers and other stakeholders. Transmission providers may also provide for consideration in the transmission planning process additional public policy objectives that are not specifically required by state or federal laws.

The proposed rule would eliminate provisions in existing tariffs that offer a right of first refusal for incumbent transmission providers to construct new transmission projects identified in transmission plans. The intent is to allow non-incumbents an equal opportunity to participate in regional transmission planning and development. The rule would not apply to merchant transmission lines, where costs are not recovered through a regional cost allocation.

In addition, the rule would require transmission providers to adopt a method to allocate transmission costs associated with projects related to the transmission plan. The intent of the NOPR as a whole is to align transmission planning and cost allocation procedures. The rule would have separate cost allocation methods to be developed for allocating intraregional transmission costs and interregional transmission costs. Furthermore, the rule notes that different cost allocation methods may be adopted for allocating the costs of:

- Facilities driven by needs associated with maintaining reliability and sharing reserves.
- Facilities being built to relieve transmission congestion and achieve production cost savings.
- Facilities being built to achieve public policy requirements established by state or federal laws.

The rules proposed by the FERC in its NOPR, if enacted, may not have a significant impact on timely enhancement of the Coos Loop to support development of renewable energy resources. ISO-NE has an open and transparent transmission planning process for evaluation of transmission system needs based on considerations of reliability and market efficiency in which interested stakeholders may participate. The proposed rule would simply require ISO-NE and the Participating Transmission Owners to amend their transmission planning processes to provide explicitly for consideration of public policy requirements established by state or federal laws or regulations that drive transmission needs, along with other factors already considered in the transmission planning process. However, it would not necessarily affect the result of the transmission planning processes. Furthermore, the proposed rule will not necessarily require ISO-NE to change its cost allocation approach, which limits the socialization of transmission costs to reliability and market efficiency upgrades.

The proposed rule also would permit each transmission provider to adopt special procedures for allocation of the costs of transmission facilities that are planned for achieving public policy requirements established by state or federal laws or regulations. Unless they are properly designed, procedures used solely for allocation of costs of transmission facilities that are planned for achieving public policy requirements established by state or federal laws or regulations may fail to stimulate development of such facilities.

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In any event, implementation of any final rule that results from the NOPR is likely to be far into the future. A final rule may not be issued until late winter or early spring 2011, and proposals to modify existing Open Access Transmission Tariffs to comply with the final rule would not be due until six months after the rule becomes effective. After such compliance filings are submitted, additional time (perhaps several months) will be required for the FERC to evaluate the compliance filings. Only then will transmission system operators, such as ISO-NE, begin to implement the tariff revisions by giving explicit consideration to proposals for construction of new transmission facilities in order to achieve public policy requirements.

3.2 Stakeholder Input

Researchers gathered input from a variety of stakeholders, either directly or through public record. This subsection distills these comments into a set of common issues, several of which underscore the existing impediments to transmission development in the North Country, the potential benefits and costs of transmission development and cost allocation approaches, and the role of transmission development in addressing State energy goals. Due to stakeholder confidentiality, names and identifying details of individual stakeholders have been withheld and many statements have been aggregated.

3.2.1 Barriers to Development

Several stakeholders commented on barriers to transmission and renewable energy development. According to stakeholders, factors that create risks can impede projects by making financing more expensive and thus increasing project costs. Low risk and good credit are key to good financing. In turn, stakeholders cited revenue certainty as a factor in successful projects. Overall, stakeholders commented that, in addition to the total cost of a project, the level of risk and who bears the risk are significant factors in determining whether a project can move forward.

Transmission Customers. According to stakeholder comment, to justify an investment, transmission developers need to identify how they are going to recover their investment costs

and who they will recover them from. In short, they must identify who is going to pay them to develop a transmission line and how they will get paid for it. In addition, stakeholders noted that because transmission development can often involve significant capital expenditures and the processes towards full development can be lengthy, reliable commitments from these customers are key to justifying investments.

According to stakeholders, renewable power generators are potential customers for transmission developers. However, stakeholders also noted that there are risks to developing transmission facilities before it is clear that renewable energy projects could go forward. Specifically, stakeholders noted the potential for stranded costs where a line cannot be fully subscribed. Furthermore, stakeholders noted that overall project risk can increase where multiple developers are needed to fully subscribe a line. This is particularly true, one stakeholder noted, where multiple renewable energy developers might be subject to a common risk such as similar environmental permitting risks or financial risks. As such, transmission planners and owners may be reluctant to build transmission unless firm demand exists for line capacity, and unless they can create reliable commitments for the transmission services.

Transmission Certainty. With regard to renewable developer needs, stakeholders commented that renewable developers are more likely to commit to building power plants where they know transmission capacity will be available. In particular, knowing that transmission will be available helps increase certainty that generators will have a way to get their product to market.⁴⁹ In addition, having readily-accessible transmission available can lower overall project costs, with less investment in transmission required to sell power. The problem of accessing transmission varies by developer, depending on location and reliability upgrade requirements. According to some stakeholders, there is a small subset of renewable energy projects with respect to which smaller investments are sufficient for them to access transmission capacity on the existing Coos Loop.

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The reluctance of renewable energy developers to invest in power plants until transmission developers invest in transmission, and vice versa, can create a “chicken-and-egg” impediment

⁴⁹ Under ISO-NE rules for reliability review, the ISO-NE must affirm that a generator will not decrease the reliability of the electricity grid. However, the review does not account for whether a generator will have firm transmission rights to sell either energy or capacity in the market. A separate analysis must be done to determine this.

that stalls the transmission development process. Put in another way, according to stakeholders, transmission developers must have a minimum density of power projects to justify development of a transmission line. However, without firm commitments to build the line, there will not be a density of renewable projects.

Credit-Worthy Partners. According to stakeholders, a number of different structures can work to pay off an investment over time. However, the debt and equity must come up front. According to stakeholders, a credit-worthy partner can also serve as a financial backstop, lowering the cost of credit. Stakeholders commented that many renewable energy developers do not have the type of credit available to help them serve as a financial backstop on projects. In addition, stakeholders noted that financing barriers can be particularly pronounced among smaller, private firms. Since the economic crisis began in 2008, access to capital and credit has tightened and may delay or derail proposed generation. Stakeholders commented that public entities can be good partners in development as they have access to good credit. Furthermore, stakeholders noted that long-term agreements (on the order of 15 to 20 years) can help establish good credit. According to stakeholders, the longer the contract is, the lower the rate can be because of the reduced risk.

Cost of Transmission for Generation Projects. In theory, according to stakeholders, under a market-based system, demand for energy and renewable energy certificates (RECs) should drive merchant developers to build and fund generation and to upgrade transmission where it is needed and economically viable. However, stakeholders noted that many smaller renewable projects may become uneconomic when faced with high transmission upgrade costs.

Potential Ways to Address Risk. Stakeholders also mentioned potential solutions to help mitigate risk. One stakeholder noted an approach used in California, where new generation projects pay down the transmission cost over time as they come online. Stakeholders also suggested contracting with a State-sanctioned authority for firm transmission rights across a line in return for payment through a fixed tariff at a negotiated rate. The entity would provide revenue certainty in exchange for the capability to import power. An authority could enter into a long term contract for development of a transmission line for a capacity equal to available resources in the area. The authority would own capacity on the line and take the up front risk, but have the credit of the State behind it. The authority could then sell capacity to developers in return for payment.

3.2.2 Benefits and Costs to the North Country and New Hampshire

Several stakeholders commented on the potential benefits and costs of transmission development in the North Country and of cost allocation approaches. The following highlights the perceived benefits and costs and summarizes additional concerns and comments received.

Benefits. With regard to impacts to the North Country, the following benefits were cited by stakeholders:

- Local job stimulation: Several stakeholders pointed to a potential increase in jobs for the North Country due to the development of renewable energy resources in the area.
- Tax payments: Stakeholders acknowledged that potential tax payments or payments made in lieu of taxes, where taxes were not required, would contribute to the local economy.
- Increased fuel independence: Some stakeholders commented that by enabling renewable energy developments which rely on local resources, the State will be decreasing its overall reliance on foreign sources of fuel.
- Achievement of state clean energy targets: Many stakeholders commented that transmission development initiatives would help enable clean energy resources which in turn would help the State meet its clean energy goals.
- Use of Local resources to meet RPS goals: Some stakeholders noted that by enabling state-based renewable resources, it could help New Hampshire keep revenue obtained from RECS in state rather going out of state to purchasing RECS from non-New Hampshire sources.
- Cheaper power: Some stakeholders believed that by using local renewable resources in the community, they could lower electricity prices.

Costs. The following costs were cited by stakeholders:

- Adverse Impact on Tourism. Some Stakeholders were concerned that transmission and generation development could result in potential environmental and aesthetic degradation, such as alteration of scenic vistas or increased traffic, which could in turn negatively impact tourism. Stakeholders commented that no master planning is in place for zoning communities in the North Country.
- Adverse Impact on Property Values. Some stakeholders shared concerns that the same environmental and aesthetic impacts could also negatively impacts on property values.
- Extraction and Exportation of Resources. Many stakeholders voiced a concern that local resources would be used to generate power for export. Furthermore, some stakeholders

worried that these resources could be put to other uses which would have a more direct benefit for local residents.

Economic Revitalization. Coos County has been experiencing economic decline over the past few years. Compared to the statewide average, the county has lower wages, higher unemployment, and a net population decrease. According to stakeholders, the decline in manufacturing, one of two major industries in the North Country, has accelerated as paper and pulp mills have closed in Groveton and Berlin. In addition, according to stakeholders, the region's other major industry, tourism, is not well suited to replace the number and quality of manufacturing jobs lost.

By some stakeholder estimates, the North Country has lost up to 2,900 jobs as result of the economic collapse and closure of pulp and paper mills and furniture manufacturers. According to several stakeholders, replacement industries are needed to remake the basis of the North Country's economy. While the renewable energy plants proposed and under development will create local demand for unskilled and skilled labor, according to stakeholders, the total number of jobs created does not compare. This is particularly true for wind farms, according to some.

One stakeholder estimated that only six full time jobs would continue beyond the development and construction phase of wind projects. Other stakeholders highlight the direct and indirect jobs associated with the biomass and wind generation as reasons to support such development. Some stakeholders cited renewable energy development as an economic development strategy for the region and cited biomass projects as a strong potential for ways to turn local knowledge and resources into an asset for the region. Meanwhile, other stakeholders questioned whether the state or the public could make other investments that would have a better impact for economic recovery.

According to many, to reverse the economic decline, Coos County needs to attract an array of high-quality, well-paying jobs. According to some, developing renewable energy projects is one way to boost the regional economy. Several stakeholders commented that Coos County has significant resources to support these projects: a strong manufacturing history, wind energy potential, logging byproduct supply, and large tracts of privately owned land to site the power generation facilities. In return, these renewable projects could bring economic development in jobs and tax revenue to support local communities.

Perceived Mismatch in Costs versus Benefits. A subset of stakeholders perceived a mismatch between the costs and benefits of the proposed upgrade to local ratepayers, businesses and residents in the North Country. Some stakeholders questioned why North

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Country stakeholders would bear the environmental and economic costs while most power generated appears to be destined for out of region and out of state consumption. Stakeholders noted that generators would invest hundreds of millions of dollars to develop power facilities but stakeholders perceived little local impact for that investment. In addition, stakeholders were concerned that because some potential non-financial costs of renewable and transmission development might be difficult to quantify, that they would not be given equal weight to other factors that were easy to quantify. Lower electricity rates, stakeholders commented, could help offset and balance the perceived costs borne by local stakeholders.

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Stakeholders also voiced concerns that private developers would build renewable power generation in the North Country and the region will accrue little benefit. Such concerns included:

- Minimal long-term job creation, particularly in wind power generation.
- Lack of local hiring due in part to a need for training in non-biomass-based industries.
- Export of wealth from the region with the export of renewable power from the region.
- Accrual of wealth to investors from energy sales and RECs despite local costs.

Other cost concerns included pressure on resources (displacing ability to generate power locally and build other industries) and environmental degradation.

Ratepayer Funding. Several stakeholders of different types, voiced an opinion that clear benefits should accrue to the ratepayers should they be required to help pay for the development of transmission.

Transmission Siting. Public stakeholders requested town hearings or project scope for town(s) affected by proposed generation plants and transmission upgrades.

Perceived High Energy Prices. Some stakeholders noted that they believed North Country ratepayers pay high electricity prices, claiming that they pay some of the highest rates in the region. (all PSNH customers pay the same rate- it does not vary by region in NH - suggestion - when the report says a stakeholder says something, I'd suggest you indicate if you have checked it to make sure it is true - just including it in the report gives it 'authenticity' without disclaimer.) Stakeholders questioned whether the proposed generation projects would lower local electricity costs.

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Local Resource Development. A subset of stakeholders voiced a desire to develop resources in the region for local consumption – i.e., community scale renewable energy development – which would not require significant transmission development. Stakeholders saw this as a

potential way to keep the benefits of the renewable development local while minimizing transmission costs.

Biomass fuel availability. A range of estimates have been released by varying stakeholders on wood products available to proposed biomass generating facilities in Coos County. As the primary firing fuel for several proposed plants, the availability and price of biomass products is of great concern as this economic input can alter the anticipated viability and profitability of proposed generation. One developer engaged Innovative Natural Resources (INR) to conduct an independent assessment of the availability and price for its proposed Berlin-NH based biomass plant. INR reported that suitable wood products can currently support roughly 30 MW generation at roughly \$32 per green ton, delivered.

3.2.3 State Energy Goals

Renewable Energy. Many stakeholders commented on the role of renewable energy in the North Country contributing towards State RPS goals which requires that 23.8% of retail electricity be produced from renewable resource by 2025. Currently, limited types of renewable resources qualify. In addition, other New England states have RPS goals for which New Hampshire resources may qualify.⁵⁰ Table 1 shows the eligibility of various renewable energy generation types by state. In all cases, biomass and wind energy qualify.

Table 1. RPS Qualifying Sources, by State

⁵⁰ Accessible at: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NH09R&re=1&ee=1.

Though the state RPSs are requirements for state retailers, the rules in many states allow retailers to purchase RECs which are derived from out of state. As such, the location of renewable energy generation is independent of the requirements.

	NH	CT	MA	ME	RI	VT
Small Hydro	yes	yes	yes	yes	yes	yes
Large Hydro						yes
Wind	yes	yes	yes	yes	yes	yes
Solar	yes	yes	yes	yes	yes	yes
Waste		yes		yes (w/ recycling op)		yes
Biomass	yes	yes	yes*	yes	yes	yes
Landfill Gas	yes	yes	yes	yes	yes	yes
Demand		yes (class 3)				yes
Ocean	yes	yes	yes	yes	yes	
Efficiency		yes (class 3)				yes

Source: New England States Committee on Electricity 2010.

* MA will conduct a stakeholder process to consider the results of a recently completed biomass study and to consider existing regulations.

Stakeholders questioned how likely it would be that New Hampshire laws might change existing rules to permit additional renewable resources to qualify. In addition, stakeholders questioned whether Canadian resources could qualify and whether they would saturate the market. In particular, **Hydro Quebec is planning three major transmission lines into southern New England: Maine, New Hampshire and Vermont, totaling 6,000 MW.** (I believe this is a not accurate, I believe the number is closer to 1200 MW). Stakeholders questioned whether this source of energy would saturate the renewable energy market, either through oversupplying the demand for RECs or taking up transmission capacity. Some Stakeholders noted concern that, depending on what resources qualified, the State could effectively export the potential benefits of renewable development to non-New Hampshire entities while paying the cost of requirements to integrate renewable resources. Other stakeholders emphasized the importance of New Hampshire resources towards meeting regional RPS goals.

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Fuel Diversity. Stakeholders noted the potential benefits of interconnecting a diverse set of in-state renewable resources. In particular, stakeholders noted a decreased dependence on foreign oil and gas as an indirect benefit of the transmission development. Fuel diversity, according to stakeholders, can mitigate electricity price increases by allowing markets to have multiple fuels to choose from. Fuel diversification is essential to enhance energy security, reliability, and energy independence, according to some, because it serves as an extra “line of defense” against shortages or interruptions in any one fuel source.

4. Cost Allocation Methodologies

The basic principle underlying the allocation of transmission expansion costs is that the beneficiaries of the transmission development should pay. The central problem is identifying the beneficiaries and then allocating the costs fairly among these entities.

Most ISO/RTOs have provisions in place that determine how to allocate costs among entities, based on the nature of the transmission project. For example, some ISO/RTOs socialize costs for certain projects that provide reliability benefits or economic benefits for electricity customers, or ratepayers. For other types of projects, including private generator projects, the developer is required to bear all costs. More recently, some ISO/RTOs have introduced provisions that address projects that help move power from areas rich in renewable energy resources to load centers where the power is needed. In addition, some approaches directly address who bears the risk associated with a project, as well as who ultimately pays for the transmission. For example, one party might pay for transmission up front while another pays for it over time. Outside of ISO/RTOs, many states have developed state-level or multi-state level policies to allocate costs for transmission development.

This section summarizes cost allocation approaches, in general, and provides detail about the specific cost allocation approaches used throughout the country.

4.1 Methodologies

4.1.1 Basic Methodologies

The following are generally accepted methodologies to allocate transmission development costs. Many of these are administered within a region by transmission planning organizations called ISOs and RTOs. These five methodologies are⁵¹:

- **License Plate:** ratepayers pay transmission rates based on the costs of transmission in the transmission pricing zones in which they are located, but are able to utilize the entire system after based on payment of such rates.
- **Postage Stamp:** transmission costs are recovered uniformly from all customers in a region, such as defined by an ISO or RTO, where the transmission was built.

⁵¹ EESI, *Typical Bills and Average Rates Report - Winter 2010*. 2010.

- **Beneficiary Pays:** costs are allocated among groups of customers based on the perceived proportionate benefits accruing to each group. Various criteria and formulae exist to determine the benefits.
- **Direct Assignment:** transmission costs associated with interconnecting a generator to a transmission line or other transmission service requests are assigned to the entity requesting service.
- **Commercial Investment** (also known as merchant cost recovery): transmission developers recover their commercial transmission investment costs other than through regulated tariffs. Typically, this involved either selling capacity to transmission customers, usually generators, through negotiated rates. Such developers could be investor-owned utilities (IOUs) or third parties, depending on state and regional rules.

4.1.2 Methodology Variations

Several variations of these basic methodologies are used to allocate transmission capacity and costs in the U.S. Many are designed to either lower overall project risk, or to distribute project risks among multiple stakeholders to alleviate barriers for an individual party.

Open Season. A competitive open season bidding process can be used initially to allocate long-term transmission rights and costs. Revenues to transmission developers are based on results of the bidding process. If a transmission line is owned by an entity affiliated with a participant in energy markets, affiliate concerns must be addressed. Generators may acquire transmission capacity for delivery of electricity to relatively high-cost import-constrained markets.

Anchor Tenant with Open Season. To fully “subscribe” the transmission line, or find enough customers, the merchant transmission developer may conduct a process known as Anchor tenant with Open Season. Under this process, the transmission developer may enter into development agreement with an Anchor Tenant under which a portion of proposed transmission capacity (e.g., up to 50%) would be pre-subscribed at negotiated rates before the Open Season solicitation of customers in a competitive auction. FERC approved this process in a February 2009 Order.^{52,53} The Open Season/Anchor Tenant Model is particularly important as a means

⁵² Order Authorizing Proposals and Granting Waivers, *Chinook Power Transmission, LLC*, Docket No. ER09-432-000; and *Zephyr Power Transmission, LLC*, Docket No. ER09-433-000, 126 FERC ¶ 61,134 (Feb. 19, 2009).



of obtaining financing before capacity is made available to all potential customers. According to FERC's 2009 Order:

The financial commitments made by anchor customers prior to an open season provide crucial early support and certainty to merchant transmission developers, which enables them to gain the critical mass necessary to develop these projects.

Participant Funding. Under a "Participant Funding" approach, the transmission customer provides funding in advance for transmission construction. The alternative is transmission owner funding, in which the transmission owner finances construction of the transmission upgrades, and recovers the funds thereafter through transmission rates.

Participant funding with priority to transmission rights. This is a variant on the participant funding method. Under this scenario, capacity in a planned transmission line is pre-sold to a generation facility owner on a long-term basis at cost-based rates to be established in the future. If potential exists to expand the line, other customers would then be given the right to acquire capacity at comparable rates, terms and conditions. The transmission owner may be subject to the traditional obligation to build new transmission capacity under tariff rules.

Purchase Power Agreements (PPA) and Long Term Contracts. PPAs are legal contracts to buy and sell energy. They specify details such as the amount of electricity to be purchased, the price to be paid for it and the time period over which commitments are valid. PPA's can help address market risk, by assuring a buyer for a product. Longer duration PPA's can help reduce financing costs more than shorter ones because they can help debt terms better approximate equipment lifetimes.

Cluster Studies and Renewable Zones. To help circumvent the "chicken-and-egg" dilemma caused by uncertainty in development, some approaches to transmission development have made use of cluster studies or have designated areas as renewable energy zones. In particular, the studies identify areas where transmission development could readily be aligned with economic renewable resources.

⁵³ A developer of two merchant transmission projects was allowed to pre-subscribe 50% of the capacity on each line to an "anchor customer." The anchor customer's agreement will serve as precedent for customers later selected through an open-season sale of the remaining capacity on each line.

Precedent Transmission Service Agreements. Used by the Bonneville Power Authority (BPA), Precedent Transmission Service Agreements (PTSA) helps confirm generator interest in transmission services and helps limit the risk that a transmission line will not become fully subscribed. In particular, it sifts out speculative projects by requiring generators to make a down-payment for transmission service and to commit to using the transmission when it is built. Though other factors may ultimately prevent a generator from connecting (e.g., such as failure to permit), this approach helps assess how serious a developer is about subscribing for service.

4.2 Application Examples

In practice, cost allocation approaches can contain a mixture of methods. Several regions and states have applied versions of the cost allocation methods noted above, with variations or a mix of approaches is used. Because separate cost allocation methodologies can be applied within a set of cost allocation rules, each section notes which method(s) the regions use for which types of upgrade.

In addition to assessing who ultimately pays the cost for transmission investments, cost allocation methods may also address how an investment is paid for, and who bears the risk of an investment throughout the project. For example, in an attempt to lower the barriers associated with investment financing, some cost allocation methodologies allow one entity to bear costs or risks up front, though a separate party may ultimately pay for the investment.

Table 2 groups cost allocations by their basic method, and notes the application (by ISO/RTO region) and any modifications of that basic method.



Table 2. Transmission Cost Allocation Application Approaches

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Method	Application	Modification
Postage Stamp		
	ERCOT SPP PJM MISO ISO-NE	Overlay & Zones Regional & Zones Projects over 500 kV Partial % is postage stamped for certain projects Only PTF projects >= 115 kV and in RSP
Direct Assignment		
	CAISO BPA	Zones & Postage stamp up front Open Season & Transmission Agreement
License Plate		
	NYISO PJM ISO-NE	Beneficiary Approval for Economic Upgrades Exception for Power Authority Projects under 500 kV Only PTF projects >= 115 kV and in RSP
Beneficiary Pays		
	MISO	Certain projects shares or totals, per size and type
Merchant Cost Recovery		
	NYISO, PJM Neptune Linden	Open Season; PPA Long-term PPA Open Season

Table 3 summarizes approaches by region and state, distinguishing how each one addresses “financing” or “who pays.” A variety of approaches are used to address both the questions of who will pay transmission costs as well as how the costs will be paid (e.g., how it will be financed). However, the issue of financing is not always addressed specifically.

Table 3. Transmission Cost Allocation Application Modifications

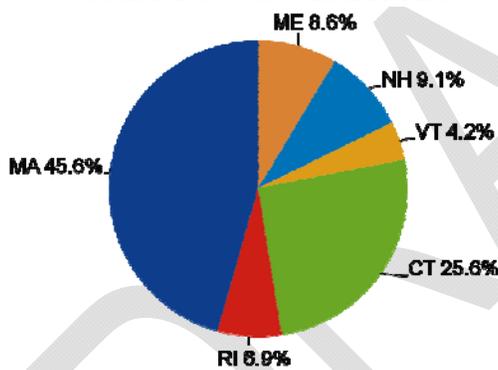
Application	"Who Pays"	How Addresses Financial Risks
ERCOT	Postage Stamp	Pre-Approved & Costed; 10% Commitment
SPP	Postage Stamp	Not directly
BPA	Direct Assignment	Transmission Agreement, Open Season
NYISO	License Plate	Not directly addressed
CAISO	Direct Assignment	Postage Stamp Up Front
PJM	Postage Stamp & License Plate	Not directly addressed
MISO	Beneficiary Pays & Postage Stamp	Not directly addressed
ID-WY-MT	Merchant	Open season; Anchor tenant
NTTG	Merchant	Open season; Anchor tenant
KS, WY, IA, ND, SD, CO, NM	Infr / Trans Authority	Varies

4.2.1 ISOs/RTOs

4.2.1.1 ISO-NE

ISO-New England is an example of the postage stamp method.⁵⁴ Under the ISO Tariff, certain reliability upgrades identified by the RSP can have their costs socialized. In particular, the costs of upgrades 69kv and above and which qualify as a PTF Facility are fully allocated across load, based on coincident peak loads. Where transmission upgrades are less than 69kv or are not classified at PTF, they are allocated per the ISO OATT under Schedule 21, "Local Service." According to 2009 data and as shown in Figure 3, New Hampshire would be allocated 9.1% of the cost, as compared to Massachusetts at 45.6% Connecticut at 25.6%, Maine at 8.6%, Rhode Island at 6.9%, and Vermont at 4.2% for transmission investments in the ISO-NE region that is deemed to improve reliability.

Figure 3. Percent of 2009 Network Load by State



Source: ISO-NE 2010

The ISO Tariff also includes a provision to allocate costs for projects with market efficiency benefits. These "economic" upgrades must be part of the RSP and regarded as beneficial to reducing regional power system costs. As with reliability upgrades, economic upgrades must qualify as PTF. If deemed as part of the RSP, and having a net benefit to the market, costs for

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⁵⁴ WIRES, *Cost Allocation: A Primer and Current Issues*. 2010.

these upgrades are allocated the same way as reliability upgrades. No economic upgrade projects have been approved yet for cost recovery under the ISO Tariff.

With regard to generator interconnection, the ISO Tariff allocates the cost of network upgrades needed to meet reliability standards to the generator, along with other associated costs for the interconnection facilities. The exception is where such upgrades would have been required to meet current system reliability needs. In these cases, costs are allocated as reliability upgrades.

Under the present ISO Tariff criteria for market efficiency or reliability upgrades, generator required upgrades to the Coos Loop (or anywhere else in New England) would not constitute a reliability or market efficiency project, and thus do not currently qualify for regional cost allocation. To change the ISO Tariff, revisions would need to be filed with FERC by the the ISO and Transmission Owners⁵⁵, but consensus among the NE states and stakeholders would be required to avoid potential administrative litigation.

4.2.1.2 California ISO (CAISO)

CAISO is an example of the postage stamp method for all network upgrades ≥ 200 kV. Furthermore, specially designated resources may use an up-front postage stamp allocation, which is later charged back to the interconnecting generators.⁵⁶ CAISO transmission investments are allocated according to their functions. For reliability or economic upgrades greater than or equal to 200 kVs and approved by CAISO, costs are financed by transmission owners and then repaid through a postage stamp rate. Specifically, all system users within CAISO are assessed a transmission access charge, allocated across energy demand, or megawatt-hours (MWh) consumed. CAISO's approval of economic upgrades depends on the extent to which benefits outweigh costs.

For merchant transmission facilities approved by CAISO, the project sponsor must pay the full cost of construction and operation. However, one hundred percent of the costs are repaid through a regulated cost recovery mechanism or a market-based cost recovery mechanism.

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⁵⁵ Similarly, a complaint could be filed with FERC by stakeholders to change existing cost allocation mechanisms, however in such instance consensus would also be necessary for the same reason.

⁵⁶ WIRES, *Cost Allocation: A Primer and Current Issues*, 2010.

With regard to interconnection facilities, generally the cost is borne in full by the generators seeking to connect.⁵⁷ However, the CAISO tariff also has a provision for what are called Location Constrained Resource Interconnection Facilities (LCRIF). These facilities are high-voltage transmission facilities which support at least two constrained resources, and are radial rather than network facilities. To qualify for the unique allocation of LCRIFs, generators must have demonstrated an interest in at least 60% of the LCRIF capacity. For these types of facilities, the tariff applies a postage stamp approach up front but recoups costs as generation comes online. Specifically, grid users are assessed a transmission access charge for any unsubscribed portions of the line, allocated to load on a MWh basis. (Transmission owners can finance the costs through FERC-approved revenue requirements). Generators pay their pro-rata share as soon as they come online. Assignment of transmission costs to generators, as they connect, based on the maximum capacity of the generator resource relative to the capacity of the LCRIF. CAISO's tariff limits the amount of costs eligible under this tariff such that the investment in LCRIFs is no greater than 15% of all high voltage transmission facilities.⁵⁸

California represents an approach that removes some of the financial barriers to generation and transmission development. The approach facilitates developing transmission to deliver new power before all the new generation is built, thus resolving the "chicken-and-egg" problem that can stall development. A project known as "Tehachapi" was the first example of a transmission investment requiring location constrained resources interconnection (LCRI) tariff. However, several other projects are being considered. In particular, California has conducted cluster studies for various regions within the state, which review accepted generation queue applications and assesses need for additional investment.⁵⁹

⁵⁷ Costs beyond direct interconnection facilities are treated similarly to reliability and economic upgrades.

⁵⁸ 24.1.3.1 (b)(1). "The addition of the capital cost of the facility to the High Voltage TRR of a Participating TO will not cause the aggregate of the net investment of all LCRIFs (net of the amount of the capital costs of LCRIFs to be recovered from LCRIGs pursuant to Section 26.6) included in the High Voltage TRRs of all Participating TOs to exceed fifteen percent (15%) of the aggregate of the net investment of all Participating TOs in all High Voltage Transmission Facilities reflected in their High Voltage TRRs (net of the amount of the capital costs of LCRIFs to be recovered from LCRIGs pursuant to Section 26.6) in effect at the time of the CAISO's evaluation of the facility."

⁵⁹ Section 4.2 of CAISO's Large Generator Interconnection Procedure (LGIP) (Appendix U to the CAISO Tariff). FERC granted the CAISO authority to use a "clustering" approach to process Interconnection Requests. In particular, clustering entails studying all Interconnection Requests made in given period as a

4.2.1.3 Electricity Reliability Council of Texas (ERCOT)

ERCOT's approach for transmission being built within Texas' Competitive Renewable Energy Zones (CREZ) is a postage cost allocation approach.⁶⁰ According to the ERCOT tariff, transmission costs for reliability and economic projects approved by the Public Utilities Commission of Texas (PUCT) are allocated to 100% to all load based on average summer peak demand. With regard to direct interconnection facilities, generators are responsible for all of the costs. Upgrades beyond direct interconnection are paid for by the transmission service provider and allocated across load based on average monthly coincident peak using a postage stamp approach. Once wind developers show commitment (through a letter of credit amounting to 10% of the project), then transmission companies will build the lines with the cost allocated 100% to ratepayers across all of the state.

In 2005, Texas State legislation raised the RPS, mandated a process be used to identify CREZs to meet the RPS.^{61,62} The legislation also required the PUCT to allow utilities or transmission service providers who developed transmission within the CREZ to rate base the costs of transmission. ERCOT worked with the PUCT to identify high-potential areas for wind and potential transmission solutions. In 2008, PUCT defined five CREZs and assigned \$4.93 billion of CREZ transmission projects to be constructed by seven transmission and distribution utilities.⁶³ The PUCT selected transmission options and established a competitive bidding process for transmission to serve these renewable zones. The process was open to outside bidders. However, recent legislation restricts new entrants.

Texas is an example where preemptive, system-wide renewable generation and transmission planning occurred to guide transmission cost allocation rules. In addition, the State was one of the first to have transmission competitively bid, rather allocated directly to a utility. Unlike other

group rather than serially when assessing system impacts of interconnection. Projects greater than 20 MW are studied in clusters while projects equal to or less than 20 MW are studied serially.

⁶⁰ WIRES, *Cost Allocation: A Primer and Current Issues*, 2010.

⁶¹ Texas Senate Bill 20, 79th Leg. Reg. Sess. (2005).

⁶² In a 2006 rule, the PUCT defined three criteria by which to identify a region of Texas as a CREZ.

These criteria are include a region's production capability, the level of financial commitment by generators in the region, and other factors such as the likely cost of transmission to connect resources in that zone.

25.174(a)(4).

⁶³ PUCT Order 33672.



ISO/RTO regions, the state public utilities commission, the PUCT was directed to have an influential role in selecting transmission projects which would by default have a rate-based cost recovery.

4.2.1.4 Southwest Power Pool (SPP)

SPP is an example of a postage stamp method.⁶⁴ On June 1, 2010, FERC approved a revised tariff for SPP, which included a new approach to allocating certain transmission costs in the region. SPP's revised cost allocation methodology applies varying degrees of regional versus local allocation, depending on transmission size, using a postage stamp approach. Projects which qualify under this "Highway/Byway" approach include projects identified as Base Plan Upgrade projects selected by the SPP Board of Directors. These include economic upgrades designated as priority projects and other projects arising from SPP's transmission planning process, including approved projects associated with wind generation resources in the region. Generator interconnection costs do not qualify, and as such remain the responsibility of the generators.

The scope of allocation varies with the size of the transmission. In particular, transmission equal to or over 300 kV or more are allocated 100 percent across the region. Transmission equal to or below 100 kV is paid for entirely within its zone. Transmission between 100 and 300 kV has one-third of the cost allocation regionally and two-thirds of the costs allocated within the zone. These regional zones correlate to existing SPP pricing zones.

The intent behind the cost allocation approach is that larger, high voltage transmission projects tend to benefit the entire region where smaller facilities have more local benefits. Also, the revised tariff more closely links the system planning process, providing a way to allocate costs designated in the regional planning process. Because the tariff focuses on transmission size and projects identified in the transmission planning process, the new tariff limits allocating transmission costs separately by function. For example, the change eliminates a previous approach to allocating wind-related projects on a MW-mile basis and allocates all qualified wind projects based on size. This assures, for example, that wind-related projects 300 kV or greater

⁶⁴ WIRES, *Cost Allocation: A Primer and Current Issues*, 2010.

will be fully socialized across the region.⁶⁵ The revised approach facilitates integrating renewable resources from the western areas of the region with load centers in the east.

4.2.1.5 Midwest ISO (MISO)

The MISO tariff's cost allocation provisions are an example of the postage stamp approach. As of the publication of this report, additional variations to the tariff are pending FERC approval, as of October 2010. Currently, the MISO tariff allocates transmission costs according to the purpose of the upgrade, including reliability projects, economic upgrades and generator interconnection projects. The allocation for reliability upgrade projects vary by size. For projects involving transmission of 345 kV or more, 80% of the costs are allocated to load within the region based on a flow-based approach. The remaining 20% is allocated to load across the entire region on a postage stamp basis, according to average coincident peak. For reliability projects between 100 kV and 345 kV, the tariff allocates costs entirely within the region using a flow-based approach. All projects must have costs exceeding 5 million or be 5% or more of a transmission owner's net plant. In addition, the MISO tariff specifies a cost allocation approach for PJM/ Midwest ISO cross-border projects. Here the allocation uses a flow-based approach to ascertain each RTO's contribution to the constraint causing the upgrade. Once allocated to each region, the costs are then allocated according to each region's usual tariff.

To qualify for cost allocation under the MISO tariff, economic upgrades must be 345 kV or greater and cost over \$5 million. Furthermore, MISO must determine that the benefits outweigh the costs. For these cases, the tariff allocates 20% of the costs to all transmission customers in the region, on a postage stamp basis. The remaining 80% of the costs are allocated across three planning sub-regions based on based on estimated benefits, and allocated on a postage stamp basis within the sub-region.

In July, 2010, MISO proposed an additional transmission cost allocation method for Multi-Value Projects (MVPs).⁶⁶ If adopted, it will result in adjustments to cost allocation for generator interconnection projects. Originally, for generation interconnection projects, generators generally had to pay the entire cost of Network Upgrades in advance of construction for projects smaller than 345 kV. For projects over 345 kV, generators had to pay 90% of the costs and 10% was allocated system wide, based on coincident peak. Where a generator could

⁶⁵ SPP Filing April 2010, pp. 8, 21-22.

⁶⁶ MISO Filing July 2010.

demonstrate that it was a designated Network Resource or that it had committed to supply at least one year of capacity when it began operation, then the generator could be reimbursed for 50% of the costs of the Network Upgrades.

MISO's proposed cost allocation methodology for MVPs allocates 100% of all Network Upgrade costs to all load and exports, using a per-MWh charge, on the basis that MVPs and their associated transmission upgrades provide region-wide benefits to the MISO footprint as a whole, from load and exports. To qualify as an MVP the transmission project must be over 100 kV. The MVP charge will be based on the annual revenue requirements reported by each MISO Transmission Owner for projects that meet the MVP criteria. The MVP charge is proposed to be applied on a usage (i.e., MWh) basis rather than a demand (i.e., MW) basis.

According to the an AWEA filing, the MVP approach would allow certain transmission development projects associated with renewable energy development to qualify for complete socialization of costs. In AWEA's words:

With respect to renewable resource development, this process would be similar to the Competitive Renewable Energy Zone ("CREZ") process that ERCOT used to identify areas (or zones) of Texas most appropriate for wind development, and then to design transmission additions needed to support development in those zones.⁶⁷

4.2.1.6 Pennsylvania New Jersey Maryland ISO (PJM)

PJM is an example of a postage stamp approach as well as a license plate approach. The postage stamp approach is for transmission 500 kV and above (all transmission service customers in a region pay a uniform rate per unit-of-service, based on the aggregated costs of all covered transmission facilities in the region). New reliability and economic-based projects less than 500 kV are recovered under a license plate approach, where costs are allocated based on flow impacts determined from peak conditions. However, PJM and FERC in continued litigation and numerous FERC compliance filing obligations have dampened use of the postage stamp cost recovery method. PJM's economic planning and cost allocation mechanism contains specific criteria for measuring benefits and costs as well as specific benefit/cost tests for evaluating projects. PJM was ordered to develop such mechanisms as a condition of its approval as an RTO.

⁶⁷ AWEA Draft Filing, Unofficial Copy. 2010 p. 24

4.2.1.7 New York ISO (NYISO)

NYISO is an example of a license plate approach to transmission cost allocation for projects related to reliability and economic upgrades. The exception is recovery of New York Power Authority's (NYPA) costs, which are socialized across all New York transmission users via the NYPA Transmission Adjustment Charge (NTAC).

According to the NYISO tariff, upgrades addressing local reliability issues are allocated to the zone or zones in which the reliability issue was occurring, where coincident peak load determines allocation across zones affected. For upgrades solving region-side reliability issues, the tariff allocates costs to the whole NYISO region, based on each zone's share of coincident peak load.

To be eligible for allocation under the NYISO tariff, economic projects must pass a cost-benefit test such that the projected benefits outweigh costs over a ten year period. In addition, the costs must be greater than \$25 million and at least 80% of the beneficiaries must approve the project. Beneficiary votes are weighted by their share of potential energy savings. As with a reliability upgrade, costs are allocated to zonal beneficiaries. However, allocation across zones is based on energy savings and allocation within zones is based on share of total energy in the zone.

Under the NYISO tariff, generators are generally responsible for costs associated with meeting minimum interconnection standards. Where a party may elect to make additional upgrades, that party may be reimbursed by other parties connecting in the future and benefiting from these additional upgrades.

Recently, two merchant transmission development projects to deliver power between PJM and NYISO used cost allocation methods outside of the NYISO tariff. The first, the Linden Variable Frequency Transformer project (Linden VFT),⁶⁸ used an open season auction approach to fund a 230 kV line that would provide additional capacity over an existing transmission line. In particular, FERC approved an anchor tenant to pre-subscribe transmission capacity prior to such capacity being offered to other developers through FERC's open season process.

⁶⁸ Linden VFT LLC is a new Delaware limited liability company, formed by GE Energy Financial Services Inc. to develop the merchant transmission project.

The second project, the Neptune RTC (Neptune), developed a long-term purchase power agreement (PPA) with the municipal utility, the Long Island Power Authority (LIPA) to help fund a new 500 kV HVDC line. Under the PPA, LIPA pays Neptune a fixed tariff with a negotiated rate for the rights to transmit power over line.

4.2.2 State & Regional

Several single-state and multi-state collaboratives have also developed approaches to transmission cost allocation. The following sections outline some of these.

4.2.2.1 Bonneville Power Administration

The Bonneville Power Authority's (BPA) is an example of the Network Open Season Approach to transmission allocation for several transmission projects in the area. In particular, BPA developed what is termed a Precedent Transmission Service Agreement (PTSA). Here, BPA offers of transmission service at embedded rates where transmission complies with certain precedent terms and conditions as determined by BPA. In the first open season, generators were given one month to sign and return the PTSA and were required to deposit an amount equal to one year's worth of transmission service. The PTSAs apply to BPA transmission only and not regional interties.

The approach was implemented to solve what was an overwhelming number of requests in interconnection queue. The approach sifts out 'speculative' projects, e.g., those not participating in the Open Season. With the open season approach using PTSAs, BPA was able to review projects with a higher level commitment, and then identify existing transmission capacity to accommodate projects. All other projects unable to connect to the existing lines became part of a large cluster study for the BPA grid as a whole.

Overall, generators pay for the cost of transmission and BPA pays for associated engineering and design studies. Where a transmission request would require payments in addition to the transmission rate listed by BPA, then the PTSA is terminated and transmission customers must pay for the required studies.

4.2.2.2 Western States

Several western states have been engaged in transmission development outside of the ISO/RTO mechanisms. These subsections describe some case examples from these states. A subsequent section describes the use of transmission authorities, also present in many western states.

The Northern Tier Transmission Group is a non-RTO transmission organization made up of Northwest and Mountain states, including: Idaho, Oregon, Montana, Wyoming, and Utah. The Group, comprised mainly of IOUs and state representatives, coordinates transmission operations and planning, and is initially focused on developing inexpensive and relatively easy improvements to grid management. They have developed cost allocation principles for transmission projects across the region, including recommendations for license plate cost recovery based on project ownership and reliability obligations.

Idaho has numerous merchant transmission projects progressing through approval stages. Per a 2009 FERC Order, these are anchor tenant with open season to secure transmission customers where an anchor tenant signs up for large portion of capacity, typically 50%, with open season for rest. Notable proposed projects are:

- TransCanada's proposed Zephyr and Chinook HVDC lines;
- Jade Energy Associates' Overland Transmission Project;
- Great Basin Transmission's Southwest Intertie Project

For the Zephyr & Chinook project, a market-driven open season process successfully allocated 3,000 MW to three wind developers building in Wyoming. The Zephyr project would originate in Wyoming while the Chinook project would originate in Montana. The open season approach allowed the transmission developer to secure enough money from customers to cover half the regulatory costs, up to a cap of \$70 million, while the investor paid for the other half of this phase. The renewable developers were required to sign no obligation Precedent Agreement and had a defined time period in which to secure a PPA before a firm transmission agreement was required, during development phase. Generators were responsible for building facilities to connect to the converter stations.

In another project, the Idaho Public Utilities Commission approved a negotiated settlement between small wind developers and a local utility to share transmission upgrade costs. In particular, 25% of the costs were paid by the wind developer, 25% were paid by Idaho Power and allocated to utility's rate base for recovery from ratepayers system-wide and 50% was advanced by the transmission developer, but refunded by ratepayers, over a term "not to exceed 10 years after the projects are commercially viable." The Idaho Public Utilities Commission noted that requiring developer payment of only 25% is beneficial to all customers because it creates an incentive for developers to consider economic efficiencies when they

choose locations for their wind farms. The renewable projects will sell their entire output to Idaho Power, whose customers are spread between Idaho and Oregon.

4.2.2.3 Transmission or Infrastructure Authorities

Several states have developed state-level authorities, called Infrastructure Authorities or Transmission Authorities (hereafter, transmission authority), to facilitate transmission development in within the State. Some examples include Colorado, New Mexico, Iowa, Kansas, North Dakota, South Dakota, and Wyoming. Transmission authorities were created by respective legislatures to address transmission needs within the state including transmission cost allocation, design studies, and environmental review. A variety of approaches have been taken to organizing these authorities. In Wyoming, for example, the transmission authority consisted of members appointed by the Governor. In addition, powers granted to the different transmission authorities vary. In Wyoming, the transmission authority was granted the ability to issue revenue bonds to finance projects.

Public entities such as transmission authorities can have broader purposes, including economic development and job creation. In contrast, the ISO-NE focuses solely on electricity and has no mechanism to take into account job creation. Wyoming, the first U.S. transmission authority created in 2004, has the stated mission to “...*diversify and expand the state’s economy through improvements in Wyoming’s electric transmission infrastructure to facilitate the consumption of Wyoming energy in the form of wind, natural gas, coal and nuclear, where applicable.*”⁶⁹

4.3 Additional Concepts

Previous to this study, and during discussions held with stakeholders for this study, additional cost allocation methodologies were suggested by stakeholders. Suggestions are aggregated below by approach type.

Ownership. One recommendation was that legislation be enacted to authorize Coos County or another economic development body to own and operate transmission facilities. A separate stakeholder proposed a sort of “private toll road” between generation and local loads. In particular, the stakeholder suggested an investment model where Coos County bonds the cost

⁶⁹ Accessible at: <http://wyia.org/about-us/>. Accessed August 3, 2010.



of transmission and the State of NH guarantees or financially backs the County Bonds, resulting in a lower rate. The bonds would guarantee a return on equity investment. A regional public authority would support Coos County in making the required investment. Each taxpayer in each community of the county would receive a direct tax reduction benefit when the county receives additional income from the project. The benefit of this approach, according to the stakeholder is that Coos County taxpayers are direct beneficiaries rather than outside investors. The approach also, according to the stakeholder, provides a faster, lower cost process ([not sure this is faster](#)), to investment and does not require a developer to pay for significant transmission upgrades beyond their own collection lines. ([this does not address investments required to facilities outside the COOS loop](#))

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Another stakeholder proposed amending RSA 162-G to make renewable energy facilities eligible for industrial development bonds.⁷⁰

Public-Private Partnerships. Additional suggestions included creating a public-private partnership with a merchant transmission provider which would allow the provider to use existing rights of way. The approach would allow a private developer to invest in a transmission upgrade in return for the opportunity to earn a return on its equity investment.⁷¹

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Transmission Authority. This entity would serve as catalyst or organizer to facilitate transmission infrastructure development, similar to other states noted above. Anbaric Power summarized how such an authority could work in the state:

One idea would be for the authority to become the customer for the capacity on a new transmission line through a long-term contract with a transmission developer. As is done in Texas the right to build the line could be put out to competitive bid, where entities like NEITC, PSNH, National Grid or other transmission developers would compete to build the line under a long-term contract with the transmission authority. As renewable energy developers then came on to the line, they would assume their proportional share of line's cost and eventually the transmission authority contract would no longer be necessary. I'm sure there are several other iterations of this approach that would hold promise for getting a line built to serve Coos County and support the economic development of the

⁷⁰ NHPUC, *Commission to Develop a Plan for the Expansion of Transmission Capacity in the North Country: Progress Report. Pursuant to SB 383 Chapter 348, Laws of N.H. 2008.*

⁷¹ NHPUC, *Background Report on New Hampshire Transmission Infrastructure, 2007.*



region. KEMA's work presents a good opportunity to explore this beyond the traditional and difficult cost allocation methods.

Reconfigure Coos Loop into a Network Upgrade. Some stakeholders have proposed re-designing the Coos Loop to make it a transmission facility where upgrades would have regional reliability or market efficiency benefits.

Equal Cost Distribution and Up-Front Financing. Instead of determining the costs of transmission upgrades payable separately by each of the generators depending on its spot in the queue, New Hampshire (or any other party providing up-front financing) could establish a cost-recovery arrangement which would impose the same cost on each of the generators until all of the capacity had been subscribed and commitments had been made to facilitate full cost recovery.

Senate Bill 164. In 2009, Senator Gallus and Representatives Remick, Rappaport and Theberge sponsored legislation that would have allocated transmission costs related to northern New Hampshire's electrical transmission system. The legislation proposed establishing the northern New Hampshire electrical transmission system improvement fund (Fund) to help cover the costs of transmission development. The legislation would have appropriated \$155,000,000 to Fund the NHPUC to administer the funds, which would have come from a variety of sources. In particular, 20% would be paid by new generation developers at the rate of \$105,000 for each developed megawatt of power. 20% would be paid by New Hampshire ratepayers through a transmission charge on electricity, 5% would be derived from state-issued bonds and 50% would be paid for through federally-funded programs.⁷² The legislation did not make it out of the Senate Committee on Energy, Environment and Economic Development.

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⁷² When SB 164 was first drafted, it appeared that American Recovery and Reinvestment Act funding would be available for transmission investments in remote areas that were rich in renewable energy resources. The final version of the bill, however, deleted those provisions.

5. Transmission Cost Applications in New Hampshire

5.1 Cost Allocation Impacts

As noted in Section 4, transmission cost allocation approaches appropriate the costs, as well as risks, amongst stakeholders. As such, the approaches address the question of who pays and how, and who takes on market and project risks associated with the project. At a high level, Table 4 illustrates how the basic cost allocation methods discussed in Section 4 allocate costs and risks.

Table 4. Comparison of Basic Cost Allocation Impacts on Stakeholders

Approach	Project Costs & Risks
Postage Stamp	Ratepayers
Direct Assignment	Generation Developers
License Plate	Ratepayers
Beneficiary Pays	Beneficiaries (combination of groups)
Commercial Investments	Transmission Developers

In general, postage stamp and license plate approaches allocate costs and risks to ratepayers. Direct assignment approaches allocate costs and risks to generation developers. Commercial investment approaches allocate costs and risks to transmission developers. Beneficiary approaches pays may result in multiple parties contributing, including ratepayers and developers.

Furthermore, additional methods have been developed to separate out the allocation of direct costs from project risk. Variations on the basic methods, for instance, can alleviate project and market risks by distributing risk across multiple stakeholders, by allocating risk to different stakeholders over different time periods in the project, or by introducing processes that clarify the demand for a product. As noted in Section 4, an Open Season approach defines a process by which to subscribe energy developers to a transmission line, before the line is built. This can help assess demand for a transmission project before development of the transmission line moves ahead, and clarify the revenue a developer would receive for their investment. Furthermore, a renewable energy developer is assured that it has transmission capacity over which to deliver its product. Anchor Tenant with Open Season addresses the risk that a line may be undersubscribed even though there appears to be demand for it. Typically, a single anchor tenant may have majority stake in a line, allocating a more substantial commitment for transmission a single entity. Precedent Transmission Service Agreements help confirm generator interest in transmission services by sifting out speculative projects before an open

season. Cluster Studies or Zone Definition can also help assure that customers for transmission development exist. In particular, studies identify areas where transmission development could readily be aligned with economic renewable resources. PPAs help provide certainty to energy developers that it can sell its product once it is built.

Table 5 summarizes at a high level how ISO/RTOs provisions, which can use a mix of approaches, allocate costs and risk. Because approaches often vary depending on the type of transmission project, and because the focus of transmission development in the North Country is to enable renewable development, the table outlines transmission cost allocation approaches related to renewable energy-related projects only. Additional stipulations exist for each of the cost allocation methods summarized in Table 5, though the table does not describe them in full. Rather, Section 4 contains additional detail, as do reference documents.

Table 5. Allocation of Costs and Risks by Example Cost Allocation Approaches

Approach	Cost	Risk
CAISO	Generation Developers	Ratepayers
ERCOT	Ratepayers	Ratepayers
ISO-NE	Generation Developers or Commercial Investors	Generation Developers or Commercial Investors
MISO	Ratepayers	Ratepayers
NYISO	Generation Developers or Commercial Investors	Generation Developers or Commercial Investors
PJM	Generation Developers or Commercial Investors	Generation Developers or Commercial Investors
SPP	Ratepayers (generator interconnection does not qualify)	Ratepayers (generator interconnection does not qualify)

NYISO, PJM and ISO-NE take a direct assignment approach or commercial investment approach where a project does not result in reliability or market efficiency improvements. As such, the method allocates both cost and risk to generation developers or transmission developers. In ERCOT, MISO and SPP, ratepayers are allocated both costs and risks for a limited set of projects related to renewable energy developments. These projects have specific criteria to qualify and are generally tied to transmission planning processes within the region. Linkage to the planning process makes sure that the projects are vetted before ratepayers bear the costs. In SPP, generator interconnection projects do not qualify.

CAISO takes a slightly different approach. For projects associated with location-constrained resource, generators must ultimately pay for the transmission but ratepayers pay for the costs up-front. In addition, cluster studies done as part of the transmission planning process help match transmission projects with generation resources, ensuring availability of resources to

subscribe to the transmission line. Furthermore, total investment in transmission associated with location constrained resources is limited, effectively capping the amount of risk ratepayers will bear.

5.2 Implementation in New Hampshire

Due to differences in regional and state regulations and to differences in the geography and characteristics of existing transmission and generation assets, methodologies used in other regions of the U.S. are not necessarily appropriate for northern New Hampshire. However, the intent behind many approaches may remain valid, or slight modifications to the approaches can make them applicable to northern New Hampshire. The following sections examine the applicability of several cost allocation methods to northern New Hampshire and outline how variations of some approaches might be applied to northern New Hampshire. First, a discussion of the impacts of basic cost allocation approaches to New Hampshire stakeholders follows.

Implementation of Basic Approaches

The direct implementation of postage stamp, license plate, and beneficiary pays approaches to transmission cost allocation in the North Country would require changes to [the ISO Tariff](#) as they are all tariff-based approaches involving regional ratepayers. Direct assignment and commercial investment projects would not require [ISO Tariff](#) changes because they do not involve ratepayers.

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- **Postage Stamp** → Requires changes to tariff
- **Direct Assignment** → Requires variations to address impediments
- **License Plate** → Requires changes to tariff
- **Beneficiary Pays** → Requires changes to tariff
- **Commercial Investment** → Requires variations to address impediments

If implemented at a state-level, postage stamp, license plate and beneficiary pays approaches would require approval by the FERC. Additional variations on these basic approaches, including transmission authorities, could be applied in a similar fashion in New Hampshire. However, in some cases, legislation would need to be passed by the legislature to provide authority (such as with a transmission authority) or to appropriate funds (such as for assistance

with studies). Transmission service agreements, Open Season, Anchor Tenant and PPA processes and agreements could be conducted through the NHPUC.

Applicability of Cost Allocation Examples

Though some methods would need to be adjusted to be implemented in northern New Hampshire, other approaches would have very limited applicability even if they were adjusted. In particular, NYISO and PJM's approaches to cost allocation are similar enough to ISO-NE's that they do not directly address current impediments to transmission development in the North Country.

With regard to SPP's highway/byway approach, only a limited set of its provisions are applicable to New Hampshire. To start, the SPP cost allocation approach does not apply to generation interconnection. In addition, because other upgrades to the transmission system in the northern New Hampshire projects would likely not cross the SPP tariff's threshold of low to high voltage, taken within the context of transmission upgrades that fit within the \$150 million range, the approach would simply allocate one-third of the costs to ISO-NE ratepayers and two-thirds to ratepayers within New Hampshire. This approach would require significant changes to the [ISO Tariff](#). A variation to this approach could allocate one-third of the costs to the State and two-thirds of the costs to North Country ratepayers. However, researchers believe that the cost-sharing split found in the SPP study is not necessarily relevant to ISO-NE or even New Hampshire. Studies done by the SPP to justify this cost-share are not directly applicable to ISO-NE or New Hampshire. Additional studies would need to be done, in a similar fashion to what was done in SPP, to assess appropriate cost allocation shares.

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In general, the five basic approaches to transmission cost allocation are applicable to New Hampshire. The next section discusses likelihood of success given stakeholder input, and apparent requirements for implementation.

Approaches to Implementing Remaining Cost Allocation Examples

The following paragraphs highlight ways in which additional ISO/RTO cost allocation approaches could be implemented in NH and what they would require to move forward.

ERCOT. At its heart, the ERCOT cost allocation approach is a postage stamp approach. State-level transmission planning evaluation and the identification of cost-effective renewable resources, however, heavily guide the selection of transmission project which can be socialized through a postage stamp approach. Were New Hampshire to implement an approach similar to ERCOT at the state level, ratepayers would be charged transmission development costs and

the NHPUC would assign a set amount for that development, and would select specific transmission options for development. Were a similar approach to be taken at the ISO/RTO level, the ISO-NE would conduct a study identifying cost-effective renewable energy zones, and coordinate with state agencies to similarly coordinate transmission design. Similar regional efforts have been underway to assess renewable energy potential in New England and propose possible transmission designs. However, there is no effort currently underway to adjust the [ISO Tariff](#) to ratebase projects without reliability or market efficiency benefits.

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CAISO. In order to implement an approach to transmission cost allocation similar to CAISO in ISO-NE, it would require a change to the [ISO Tariff](#) to define location constrained resources.

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The revisions would have ratepayers cover development costs until power developers come online. Implementing a state-level approach would entail collecting funds from state ratepayers to pay for transmission until power developers were to come online.

MISO. The proposed MISO MVP approach would allocate costs to load sources and export sources on a per-MWh basis. As such, renewable energy developers would share a portion of the costs. Because New Hampshire is a net exporter of power, allocating costs to loads at a high-level could indicate one should allocate a share of the costs to other states. This implementation approach would require changes to the [ISO Tariff](#). Should the approach be implemented within the State only, a charge would be assessed to ratepayers based on their relative load.

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- **“ERCOT” State Approach** → Requires allocating costs to ratepayers
- **“CAISO” State Approach** → Requires allocating risks to ratepayers
- **“MISO” State Approach** → Requires allocating costs to ratepayers and power developers

Overall, a state-level implementation of ERCOT and CAISO approaches would allocate costs or risks to ratepayers within the State. MISO would allocate costs to rate payers and power developers.

In implementing a rate-based cost allocation approach, the cost allocation mechanism must specify the ratepayers from whom the costs will be recovered. In particular, there are multiple electricity providers operating in the State and all or some of the cost could be distributed across

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the customers of these providers. In addition, any such approach would require modifications to the [JSO Tariff](#). Approaches that allocate costs to ratepayers would need approval by FERC.

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In particular, as noted earlier, [the ISO-NE Tariff contains provisions](#) for transmission over local transmission facilities (LTFs). Electricity rate adjustments associated with upgrades to the Coos Loop would likely go into the appropriate provider's [Local Service Schedule](#), and be recovered by the use of their system.⁷³ [Another](#) example is a subpart of the Northeast Utilities tariff that relates specifically to [Connecticut for coverage of localized PTF transmission development](#)⁷⁴. By isolating a sub-group of ratepayers, the rest of New England does not cover these costs. In order to make this adjustment to the tariff, a FERC filing would be required.

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5.3 Ranking & Suggested Approaches

This study used a series of criteria to rank cost allocation approaches for implementation in New Hampshire. These criteria, in no particular order, are:

- Public support
- Ratepayer Impact
- Generator Impact (e.g., viability for generators to connect)
- Regulatory viability and support
- Timing and ease of implementation

Discussions with stakeholders indicated a strong resistance to any plans that would modify the existing cost allocation approach in the [JSO Tariff](#) or that would increase costs to electricity ratepayers. In particular, there was a strong preference among the public and public advocates, among others, not to have ratepayers pay. As such, approaches involving ratepayer impact ranked low with regard to public support and ratepayer impacts. Though one variation on ratepayer involvement is to have ratepayers effectively make a short-term loan rather than to

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⁷³ The appropriate entity would depend on who owns the transmission system, and which rates the costs are allocated from.

⁷⁴ [The "Localized Cost Responsibility Agreement\(s\)" referenced herein refer to costs that although associated with a reliability upgrade, exceed ISO-NE's reliability requirements due to aesthetic or other non-reliability related cost approved in the state siting process. The incremental cost associated therewith are not regionalized, but instead are allocated to the local area where such costs were incurred pursuant to a FERC filed agreement.](#)

pay the costs, stakeholders showed concern about assuming risks when they did not find any tangible direct benefits in return. For example, stakeholders perceived the promotion of transmission development and renewable energy in the North Country as state policy-based initiatives, with potential indirect benefits to them, but limited direct benefits not worthy of adopting risk. Generator impacts appeared to be beneficial as generators would be able to pass on costs or distribution risks. Regarding timing and ease of implementation and regulatory viability, approaches which incorporate rate-basing of costs or risks would require FERC approval.

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Approaches that did not require ratepayer involvement appeared to rank high with regard to public support and ratepayer impact. However, in order to enable renewable resource projects to move forward, additional measures could be taken which operate within the current regional cost allocation framework, and which promote transmission development. Timing and ease of implementation and regulatory viability and support also rank slightly higher in this regard given that approaches would likely use mechanisms such as PPAs, open auction and transmission authorities, already used in the U.S. Generator impact could vary depending on the extent to which these approaches fully cover transmission costs or risks.

Initiatives in which the State takes on the costs or risks associated with cost allocation are apparent in some state approaches to cost allocation – in particular approaches involving transmission authorities. Here, there are no ratepayer impacts. However, New Hampshire citizens would share the costs or risks of a project. The extent of the allocation amongst developers and the public would depend on the specific plan. For example, in some states, the state's involvement is simply to provide a loan or cheaper financing, and not cover the full expense of the transmission costs. In other cases, subsidies are provided. With regard to public support, the widely common perception that the benefits of the developments address state-level goals, rather than ratepayer interests, would rank this approach higher than a ratebasing approach with regard public opinion. However, the use of State funds needs to be carefully assessed to attract support. With regard to regulatory viability, this type of approach appears to rank highly as approval would not be required by agencies regulating electric utility rates. With regard to support and timing and ease of implementation, this would likely depend on the legislative process and the ability to pass the required legislation to authorize funds and responsibilities.

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Results Summary

A review of cost allocation approaches and ways to implement them in New Hampshire indicates that there are available a variety of means to address barriers to transmission

development in the North Country. For example, the “chicken-and-egg” problem of transmission development appears resolvable through a variety of financing approaches which disperse project risk. In addition, firm commitments by electricity customers and firm commitments by transmission customers, can help identify demand.

Non-tariff based approaches to transmission cost allocation are relevant to northern New Hampshire, and include such approaches as transmission authorities, PPAs, auctions and up-front loans or payments. The transmission authority approaches would not require changes in the ISO Tariff regarding cost allocation, but would require certain FERC filings related to transmission operation and control. However, the establishment of a transmission authority might be more contentious and time consuming to put in place as opposed to other near term strategies to develop transmission,

As a result of its analysis, this study identifies the direct assignment approach and the commercial investment as recommended approaches. The following variations are viewed as high value tools for developing the required transmission facilities in northern New Hampshire:

- Commercial Investments
- Direct Assignment
- Purchase Power Agreements
- Transmission Service Agreements
- Anchor Tenant or Open Auction
- Transmission Authority
- Up-Front Loans with Repayment by Generators

Section 7 provides detail on proposed framework for an action plan on transmission cost allocation which incorporates these elements, and makes them specific to the State of New Hampshire and the North Country.

The following approaches are valid and often high-value approaches where they are used. However, their benefit for use in the North Country appears to be limited due to their time to implement, ability to address North Country development barriers, or likely support amongst stakeholders. These include:

- Socialization of costs in customer ratebase
- Identification of Renewable Energy Zones;
- Highway-Byway approach

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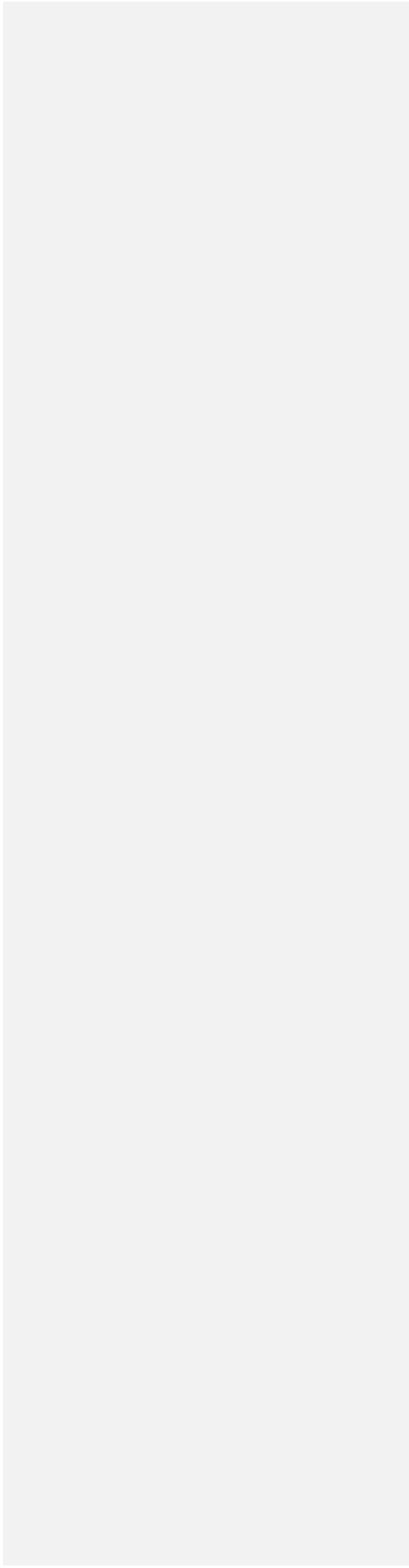
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6. Financial Studies and Analyses

To assess the application of cost allocation methods in northern New Hampshire, researchers compiled information on the costs and benefits of transmission and of cost allocation methodologies on stakeholders. The following section summarizes costs and benefits, according to available information. It then assesses the impact that transmission costs and benefits might have on local stakeholders in northern New Hampshire.

6.1 Cost and Benefit Factors Summary

6.1.1 Costs

Attempting to determine the cost of transmission upgrades without performing a detailed engineering analysis and design is difficult. As such, current estimates are rough. Nevertheless, they provide a rough assessment of the scope of potential costs. The intent of this study is to assess how to allocate costs on the order of \$150 million, plus or minus twenty percent. KEMA believes that such costs represent a reasonable range for integrating 400 MW of additional power into the Coos Loop.

6.1.1.1 Financing

Few details were available regarding the financing of proposed transmission and generation projects in the North Country. In addition, information about the finances of renewable developers is not generally publicly available and is difficult to assess in many cases. Furthermore, generalizations are difficult to apply when assessing the specific advantages and disadvantages of a particular cost allocation methodology for the North Country. Nevertheless, it is worth noting that the financing costs for renewable energy developers can range from 1.5% to 6% of the cost of a project. Mechanisms to reduce financing costs can lower overall project costs, and in some cases make a previously unattractive project appear to be attractive. This is especially true for smaller developers where the cost of financing can be higher than for larger, more established companies. Furthermore, financing costs are likely factored into the electricity prices offered by a developer. As such, the higher the debt level, the more developers may need to charge for their commodity.

6.1.1.2 Relative Cost of Designs by Capacity

Transmission development costs can vary by the amounts of renewable power being considered (e.g., \$/MW to connect varies by MW connected). As such, a project designed for

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400 MW would likely be more expensive than one designed for 200 MW. In addition, because different approaches might be taken to developing transmission to connect different amounts of renewables, the \$/MW costs could vary depending on the total MW's being discussed. For example, it could be that building for 400 MW is more expensive than building for 200 MW, but that building for 1,000 MW is less expensive on a \$/MW basis than building for 400 MW. Overall, this implies that the design of a transmission project is key in determining the cost per MW connected. Furthermore, a piecemeal, incremental approach to transmission development could come at a greater cost than a plan that considers the full potential under a single design.

6.1.1.3 Electricity Prices

Electricity prices depend on a number of factors, including electricity supplier, sector type, and for the commercial and industrial sectors, peak demand. New Hampshire has a deregulated competitive market for electric power. As such, customers can choose who they purchase power from.

Residential electric rates in New Hampshire vary from about 0.13 to 0.24 \$/kWh, depending on utility, with an average of about 0.17 \$/kWh. For the non-residential sector, rates vary from about 0.12 to 0.20 \$/kWh, depending on utility and peak demand.⁷⁵

Table 6 illustrates estimated residential electricity rates by utility for 2009.

⁷⁵ EESI, *Typical Bills and Average Rates Report - Winter 2010*. 2010.

Table 6. Estimated Residential Electricity Rates by Utility

Company Name	Rate (\$/kWh)
United Illuminating	0.24
Fitchburg Gas & Electric Co.	0.20
Connecticut Light & Power Co.	0.20
New Hampshire COOP*	0.20
Commonwealth Electric	0.18
Bangor - Hydro	0.17
Boston Edison	0.17
Public Service Co. of NH	0.17
Narragansett Electric Co.	0.16
W. Massachusetts Electric Co.	0.16
Central Vermont Public Service	0.16
Central Maine Power*	0.15
Unitil Energy Systems Inc	0.15
Massachusetts Electric Co.	0.14
Granite State Electric	0.13
New England Average Bill Amount	0.17

Source: Adjusted from EEI 2010

* Estimated by PSNH.

Electricity bills include charges for electricity generation, transmission and distribution, along with other charges. According to PSNH, the transmission component of their electricity rates constitutes around 10%. Regarding additional transmission development in the North Country, an increase in rates were ratepayers assessed the full cost, as a rough estimate, would approximate 1% to 2% of current average electricity rates.⁷⁶ (could the NCTC see this math?)

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6.1.2 Benefits

There are several potential benefits with transmission development, including its creation of a pathway between renewable energy resources and electricity markets and consumers. Often,

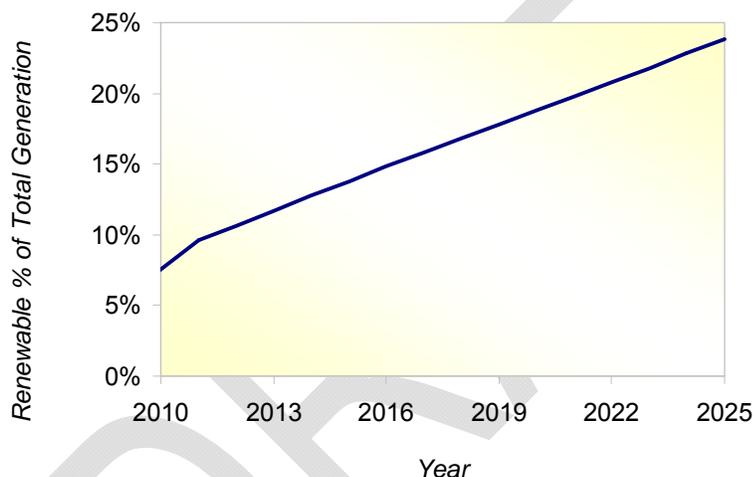
⁷⁶ This estimate is an approximation based on a 15% carrying charge, average electricity prices and assumes the full cost of the \$150 million estimated transmission cost. This approximation does not necessarily recommend that ratepayers pay for the full cost of transmission. Furthermore, additional details about the actual cost of transmission, allowed recovery rates and which ratepayers would bear the cost would be needed to improve the approximation. However, it shows a sample calculation for approximating a potential increase in rates.

renewable generation facilities have immobile fuel sources. As such, transmission is key to getting it to market. The following subsections highlight the potential benefits of transmission development, and the indirect benefits of its enabling renewable resources.

6.1.2.1 Renewable Energy Goals

As noted earlier, New Hampshire law requires each electricity provider to meet customer load by purchasing or acquiring RECS, certificates representing generation from renewable energy based on total megawatt-hours supplied.⁷⁷ Figure 4 illustrates that standard over time.

Figure 4. New Hampshire Renewable Portfolio Standard Requirements over Time



As part of this requirement, electricity providers can purchase RECS independently of power. Furthermore, electricity providers can purchase RECS originating from outside of the State. In turn, other states with similar requirements to purchase RECS can acquire RECS from within their state or outside of their state.

With regard to transmission development in the North Country, because it enables renewable development within the ISO-NE REC market, it would have an impact on the supply of RECS

⁷⁷ RSA 362-F.

available to the region. However, it is uncertain what role these renewables will play, as other regions within New England are developing renewable resources, and associated RECS. Furthermore, RECS will ultimately compete on price, a factor determined by the generator of the REC.

6.1.2.2 State Energy Consumption Goals

As noted in Section 3, in 2006, the Governor set a goal of having 25% of the state's energy requirements be met with renewable sources by 2025.⁷⁸ Towards this goal, in 2009, the State contracted with ConEdison to procure 25% of its energy from wind power over an 11-month period at a cost of \$4.4 million. In 2009, New Hampshire state offices and buildings consumed almost 1,000,000 mmbtu, of which roughly a third was electricity, and spent \$22,484,722, of which electricity costs constituted over 60%.⁷⁹ In theory, the development of transmission could enable the development of renewables in the State, contributing towards its goal of using renewable resources, and doing so with local resources.

6.1.2.3 Economic Development

Many stakeholders have discussed the potential for transmission development to lead to economic revitalization in the North Country. Though the economic impact of transmission development in the North Country is relatively small, the indirect impact through enabling renewable resource development could be sizeable. The following summarizes publicly available information regarding economic impacts from transmission development and the subsequent development of renewable resources.

Tax Revenue

Industrial and generating facilities pay property taxes to the city or town where the facility is located. In some cases, renewable energy generators may receive local property tax exemptions for certain wind, solar and biomass projects under New Hampshire statute RSA 72:61-72 and some unincorporated areas in Coos County are not subject to property taxes. However, some facilities have opted to pay the city or town, in the form of a Payment in Lieu of

⁷⁸ Accessible at: online at: http://www.nh.gov/oep/programs/25_x_25/index.htm. Accessed August 25, 2010. Energy requirements include transportation and heating energy and electricity generation.

⁷⁹ New Hampshire State Energy Manager. *State of New Hampshire Energy Management Annual Report for State-Owned Buildings and Fleets: Fiscal Year 2009*. 2009.

Taxes (PILOT), to compensate the local government for some or all property tax lost. According to the New Hampshire Office of Energy and Planning data, 84 cities and towns offer property tax exemptions, which are intended to attract developers that may have otherwise built their facilities elsewhere.

The PILOT payment depends on the facility location, and is a negotiated agreement between generator and local city or town. Developer Noble Environmental Power listed a typical payment of approximately \$5,000 per MW per year for a 15-year contract, and noted a \$21.4 million payment over 15 years for three wind park facilities in Clinton County, New York. In all cases, the PILOT does not exceed what would have been paid in property taxes.

Project developers may also make lease payments to allow the facility to be sited on landowners' property. The amount of most lease payments is confidential, and detailed in private contracts between parties. Lease payments directly benefit the landowner, but add additional indirect benefits to local communities, depending on the land ownership. If the ownership is local or regional, these payments are more likely to stay within the community. This effect of local spending, called the Local Multiplier Effect, exponentially increases the dollars spent on local goods and services. For every \$1 spent locally, \$0.45 is in turn spent within the community compared to \$0.15 on non-local spending.

Jobs

Renewable energy facilities employ a range of occupations in two distinct phases: short-term development and construction and long-term operation and maintenance. The first phase creates the highest employment phase in multi-year development and approximately 1-2 years under construction. When completed, the facility employs fewer workers, but these operations and maintenance positions are permanent and long-term. The proposed power line upgrade is not expected to result in significant job creation, and could be handled by existing employees, depending on the transmission line ownership structure.

Since the ISO-NE interconnection queue contains wind and biomass projects proposed in Coos County, our job creation discussion is limited to these fuel types. Wind and biomass facilities both undergo short term and long term job creation phases but differ in the overall number of positions created. A literature review of existing economic potential impact studies suggest a range of direct jobs created in wind and biomass. For example, biomass estimates range from

234 to 455 jobs created per 1 million tons of wood biomass. Of these jobs, 117-161 are in logging, transportation and plant operation.⁸⁰ The larger the plant, the more woody fuel required, the more jobs are created. Wind generation requires a range of 40 and 160 direct construction jobs per 100 MW of wind construction.

Renewable energy developers hire a mix of locally available and outside services. In practice, this leads to a wide range of local hiring, which depend on project location and local workforce skills. Estimated local hiring as percent of total hires starts at 10% and up. Noble Environmental Power reported 15 construction hires and 6 permanent hires for its proposed 100 MW wind park. Biomass facilities are considerably higher since the wood product fuel must be sourced and transported locally.

Job creation represents a range of occupations, and expertise and wage levels, and varies by generation fuel source. To illustrate, Noble Environmental Power proposed 100 MW wind park in Coos County will generate jobs will employ the following types of occupations⁸¹:

- **Pre-development and development phase:** Project developers; Field engineers; Environmental managers and consultants; Legal and permitting support; Community outreach; Document control; Administrative and office support
- **Construction phase:** jobs created include all of the above, plus construction-related positions; Transportation managers; Contract and sub-contract managers; Project controls engineers; QA/QC technicians; safety technicians
- **Operational phase:** Project managers; Project coordinators; Production managers; Wind turbine technicians; Wind turbine maintenance; Administrative and office support

These positions average an estimated annual wage of \$45,000 per year, significantly higher than the Coos County 2008 average wage of \$30,500, according to Noble. These direct jobs effects have the potential to create additional rounds of economic activity through indirect jobs, such as contracted services not directly employed by the developer, and *induced effects* that result from increased regional employment. These effects are typically housing and household goods and services, many of which are purchased locally.

⁸⁰ Based on a Massachusetts study (Timmons et al 2007) biomass electricity plants using 1 million tons of wood biomass per year.

⁸¹ Accessible online at: <http://www.noblepower.com/faqs/wind-energy-economy.html#three>.



Coos County Jobs Impacts

Five generator projects in Coos County are listed on the ISO-NE interconnection queue. Additional proposed projects may follow, based on the abundant wind power potential in the region. These projects combined total 314 MW wind and 107 MW biomass. (include the date for this total because the 180 MW wind project just dropped out)

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While the total job impact in Coos County is unknown since the renewable energy projects are in development, developers have released some data to show potential job creation. For example, Granite Reliable Power reported spending \$4 million development costs as of 2007. Of that, 40% or \$1.6 million was spent on Coos County good and services, and an additional 20% in other New Hampshire counties on civil engineering, surveying, wetland scientists, and related permitting services.

For all jobs created locally, impact on the local community is considerable since more of these wages are likely to stay within and circulate among local businesses. According to the Institute for Local Self Reliance data, for every \$1 spent locally, \$0.45 is spent locally compared to \$0.15 for every \$1 spent on corporate goods.⁸²

6.1.2.4 Reliability Benefits

Electric reliability benefits refer to improvements in electricity service related to improvements in power quality, the reduction in outage durations, or the avoidance or reduction of electricity outage frequencies. Improved reliability can attract or retain businesses and jobs, and local governments can benefit from reduced burden on local fire, police and other city services that assist during blackouts. Because the Coos Loop has a limited impact on the larger electricity grid, upgrades to the system are not likely to have reliability benefits for the larger system.

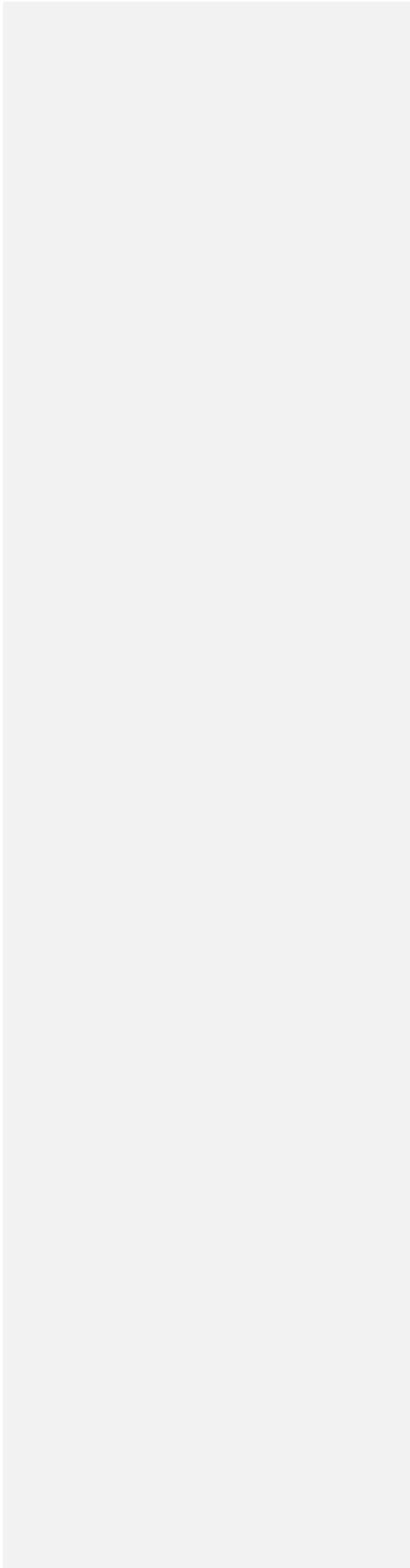
Rather, any improvements in reliability would be local. (the reason the Coos loop is not paid for regionally is because it does not meet the definition of PTF, however even if it was paid for regionally new generation connections and required upgrades would need to be paid for by the generators based on the current ISO tariff. I believe the wording in this and other sections of this report should make this point clearer.

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⁸² Vellequette, Larry. *Toledo Blade*, Economic Slump Lifts Buy Local Movement: Dollars Stay in Area, Have More Impact, December 19, 2009. Accessed August 15, 2010 at: <http://www.toledoblade.com/apps/pbcs.dll/article?AID=/20091213/BUSINESS03/912139999>

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7. Framework for an Action Plan

This section outlines a framework for an action plan to pay for transmission upgrades to integrate 400 MW of renewable generation in the North Country. As discussed earlier, several options exist for allocating costs to develop transmission in the North Country. The following is one approach which the analysts believe has a high probability of success in northern New Hampshire. In addition, as the approach considers cost assignments outside of the ISO Tariff, it may also be useful for stimulating renewable development in other parts of the State.

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7.1 Proposed Framework for an Action Plan

The proposal to allocate costs for transmission development in the North Country would use the existing ISO-NE framework of allocating transmission costs to renewable energy developers, but would also take additional measures to remove barriers currently impeding transmission development. In short, it is a modified direct assignment approach designed to reduce development barriers. (See discussion of direct assignment approaches in Section 4). The ability of this plan to fit within the existing ISO-NE cost allocation framework simplifies the approval process and places the timeframe for approval squarely in the hands of the State. Furthermore, the modification it offers to reduce development barriers means that it fits within the State's goals to promote transmission and renewable energy development in the State.⁸³ (See Section 3, above, for additional discussion on State goals and actions regarding renewable energy). Additionally, optional provisions could ensure local benefits from the development which would help garner support and address needs for economic revitalization. Overall, the proposed framework for an action plan provides a flexible framework under which stakeholders can negotiate successful ways to promote transmission development while meeting State and local goals.

⁸³ The plan does not address stakeholder concerns with renewable development, as it is outside of the scope of this assignment. However, it appears that additional measures could be taken to help address stakeholder concerns about the types and size of renewable development in the North Country. Furthermore, KEMA believes that such measures would not interfere with the cost allocation framework recommended by this study.

7.2 Approach Description

The primary mechanisms to help stimulate renewable energy development are a State-funded loan and a purchase power agreement (PPA). The use of a PPA seeks to reduce project risk for developers by securing the sale of plant production over an extended time period. The intent is to reduce the cost of capital and promote more favorable debt service requirements. Any loans, or subsidies, would then be paid back to the State over time through discounted electricity rates. The intent is to provide a predictable renewable energy source for the State, funded out of an identifiable and capped budget item. Overall, this approach would address current barriers to development and align with current State initiatives to reduce fossil fuel energy usage. Furthermore, because ratepayers do not bear the burden of project costs or risks, the approval process would be limited to the NHPUC and the State government.

Figure 5 depicts the basic framework for this cost allocation methodology. Specifically, the State would provide an up-front loan or low-cost debt to renewable energy developers to assist with project financing. In addition, the State would make a commitment to procure power from the renewable energy developers, with the stipulation that it would then receive electricity at a rate less than the current generation component of the retail rate paid by within the State. Over time, through reduced rate energy purchases, the State would recover the value of its payments to the renewable energy developers. The renewable energy developers would remain subject to the ISO Tariff provisions of Schedule 22 or 23 and request a full deliverability generation interconnection study. By providing up-front funding and offering a commitment to purchase their product, this approach is intended to ease the financing burden of renewable energy developers. In addition, the approach would better assure the transmission developer that renewable energy developers will in fact connect to the system they develop. Because the State would recover its “up-front” costs over time, it would be paid back its investment. Such commitments would help the State meet its goal to procure more renewable energy and promote renewable energy development in the State. To ensure local benefits are reaped from the renewable energy development, and to promote support for the proposal within the North Country, the State could further decide to offer reduced electricity rates to the Coos County municipalities.

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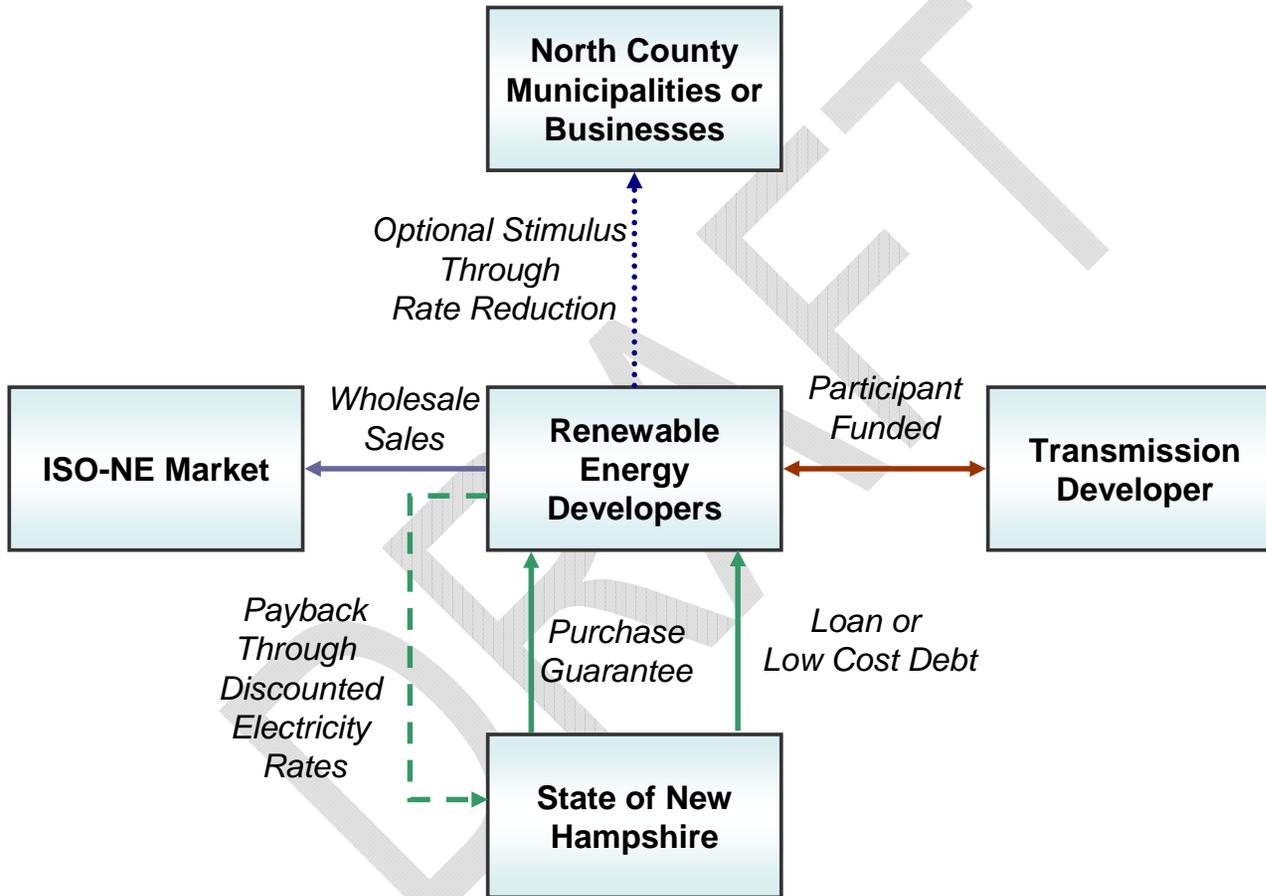
Deleted: , in turn, would negotiate a transmission service agreement with the transmission developer to provide firm transmission rights and the transmission developer would work through the required processes to make transmission system upgrades. ¶

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Figure 5. Action Plan Framework

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7.3 Implementation Flexibility

The plan proposes a flexible approach to transmission cost allocation within the proposed framework. In particular, it proposes using a variety of financial tools as necessary to move the plan forward. In other words, where support is difficult to garner, alternative approaches may be viable. In addition, the plan does not propose a specific loan payback time or percent interest. Rather, the plan proposes negotiating terms according to the cases of individual developers and suggests processes for developing these terms. The following discusses potential variations on the basic approach, highlighting where variations could address potential obstacles.

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Engagement Agreements amongst Parties

Functionally, this cost allocation approach could be implemented a number of ways. Two ways are described here. In both, a Load Serving Entity (LSE) would contract to provide, renewable power to State office buildings. **Also, the renewable developer would negotiate transmission agreements with the transmission developer (once the power enters the PTF system it is treated like any other generator., no special or different arrangements are needs or can be made)** [I think that these generators would simply be left with taking Local Service under Schedule 21, and this is a peak load based tariff recovery mechanism that charges all Schedule 21 customers a slice of all of NU's costs for its Non-PTF, and credits revenues from other revenues such as RNS. In other words, there is no deal to offer here, as any change in our cost recovery or special discounted rate requires a FERC filing]. In one approach, however, the State would negotiate a PPA directly with the renewable energy generators and the LSEs would have the obligation to deliver power purchased by the State and provide other supplemental services to deliver firm power to the State. The LSE's would then recover their costs through their usual tariff. Any added energy delivered by the LSE could be charged at a fixed rate, adjusted according to the proportion of energy the LSE passes on from the renewable energy developer at a discounted rate, or set at a lump sum amount.

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Alternatively, the State could negotiate a "State Government" tariff for an electricity rate below current rates charged to the State. Concurrently, the LSE would negotiate a PPA with the renewable generators. **As before, the renewable energy generators would negotiate an agreement with transmission developer (see above).** To facilitate tracking of loan recovery through power purchases, the State could purchase the energy as a lump sum amount.

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Identifying Developers

To be equitable, a general offer to negotiate a PPA should be made available to any new developer that would want to connect in northern New Hampshire, though individual loans may vary according to the renewable developer's financial circumstances. Currently, 400 MW of renewable generation projects are in the ISO-NE queue. However, additional renewable developers may also seek to connect to the transmission system. As such, the State should consider ways to assess the amount of likely, developable renewable energy capacity which the transmission development could interconnect. A simple approach would be to provide a timeline over which interested parties could register their interest. This would also help provide a better sense of the types of upgrades to the transmission system might require. An approach that requires more commitment on the part of the developer, such as used by BPA where developers require deposit payments to ensure a minimum level of commitment, could be employed to further gauge the seriousness of intent. Concurrent identification of potential developers could benefit the project by allowing the transmission developer to subscribe larger portions of the line, thus reducing the transmission developer's risk.

Addressing Potentially Limited Funds

As the approach requires repayment to the State and couches it within the State's energy cost budget, the State could fund only a limited number of projects before the payback on investment becomes too great. The limiting factor is the State's projected load, as the State's ability to recover its costs depends on the ability to receive discounted energy. With the State's energy needs already met, it cannot offer additional financing through this payback mechanism. To address this issue, and to be equitable, the renewable energy developers should make the same offering of reduced rates for up-front funding or power purchase commitments to other parties who want to invest similarly. However, lacking interested investors, the State might consider using financing tools such as have been employed by transmission authorities, such as tax-exempt bonds, to supplement this approach. In particular, the State could directly finance bonds, or indirectly finance them through a separate agency, for the development of projects. Consistent with the approach of many states with transmission authorities, the State could issue bonds through a separate entity other than the State, allowing bond liabilities to be that of the entity and not of the State. The potential disadvantage of this approach, however, is that the transmission authorities would not have a credit history. Further, the State would need to decide on what restrictions it would put on owning the transmission facilities. Some transmission authorities, for example, divest them as soon as they become economic, and others are able to own the transmission investments but must lease them. Alternatively, the State could use existing authorities, such as those similar to the Community Development Finance Authority, or issue the bonds directly in a separate process. In addition, using an

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approach from states with transmission authorities, the State could lower the cost of debt by making the bonds tax exempt. Current efforts are underway by several transmission authorities to seek federal tax exemption for such bonds.

Transmission Development Options

According to FERC's tentative guidelines put forth in its June 17th NOPR, the transmission developer could be either an incumbent or a non-incumbent. Because an incumbent has access to and ownership of existing rights of way, it is feasible that the incumbent would have different costs and risks associated with the transmission development. Either way, revenues could be recovered through a cost-based approach or other cost recovery mechanism approved by FERC. The project would have to meet certain FERC criteria. In either case, it is likely that the transmission would be turned over for ISO-NE operation.

Electricity Pricing in PPAs

Ultimately, the success of the approach would rely on the ability and willingness of the developers to provide below-market rates. In some cases, a renewable developer may not be able to offer an electricity rate lower than the prevailing market price, even where measures to reduce risk have reduced the cost of capital. Such cases might exist where transmission interconnection costs become a significantly large proportion of the total costs or where other operating costs are significant. Where the state feels that it is important to encourage these renewable investments for purposes of meeting RPS goals or economic development goals, the State could choose to subsidize development and not recoup all of the costs of its investments from rates. To help evaluate what costs are reasonable, the State could use, as a baseline, other prices it has paid to procure renewable energy. In addition, the State could choose to require that the loan be paid back in installments to circumvent the payback mechanism that relies on reduced electricity rates.

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7.4 Sensitivity of Approach to Costs

The recommended approach to cost allocation in northern New Hampshire would depend on a number of factors, including the State's projected energy consumption, the renewable energy developers' price to produce, and the cost of the transmission upgrade. Where development costs exceed the amount the State is able to provide and have a reasonable payback period, other approaches such as State or private bonds could help. As such, increases in transmission costs may affect what combination of approaches the State pursues.

Information about the finances of renewable developers is not generally publicly available and is difficult to assess in many cases. Furthermore, generalizations are difficult to apply. As such, the State or a separate entity such as a transmission authority would need to assess what minimum funding, in conjunction with PPAs, would be needed to enable development. Furthermore, a complete assessment of the State's energy use would be required to determine the amount of money that could be loaned up front with a reasonable payback period.

7.5 Distribution of Upgrade Costs and Benefits

Transparency in renewable developer financing is key to assessing the needs of developers. In particular, the intent is to provide enough support to overcome development barriers. Support beyond this would expend funds not fulfilling their purpose. Assessing developers' needs is particularly important as the situation of developers can be quite varied, and as the cost to connect resources can vary by the amount of resources connecting.⁸⁴ In addition, in some cases, the generator connecting just after another could face lower interconnection costs due to upgrades made by the former.

With regard to the costs and benefits of the proposed approach, the developer would benefit by having lower barriers to investment. However, to the extent that a developer already had a PPA commitment, that developer would be ineligible to participate in a mechanism that repays through reduced rates. In such cases, low-cost debt could be provided if it was determined to be needed. All developers receiving such assistance, however, would have to pay back the funds over time, unless the State decided that for policy reasons, it wanted to subsidize the developer to promote renewable development in the State.

Transmission developers benefit from this approach by gaining a clearer understanding of the demand for their assets and by having an increased confidence that power developers will want to connect. Typically, they would be expected to finance the cost of transmission, and be engaged in the development, design and construction processes.

The State would benefit by being able to meet its goals for renewable development in the North Country on a timescale it could influence directly. In particular, it would secure predictable sources of renewable energy to help it meet its goal of 25% clean energy by 2025, and it would assure that the renewable power developed to help meet regional RPS goals are located within

⁸⁴ For example, the \$/MW connected varies as MWs connected increases.

the State. While the State would not pay directly for these benefits, the State, however, would bear a risk regarding the payback of its investments. The State could help lower that risk, by assessing the commitment of developers in a variety of ways.

The North Country could potentially benefit with cheaper electricity rates. They may also benefit from jobs and new tax revenue associated with the projects. Though some stakeholders have concerns about the impact of larger-scale renewable development in the community, the selection of renewable projects and implementation requirements could potentially limit some of these concerns. The authors believe, however, that while these concerns should be recognized, the processes to address them should be separate from the development of a transmission cost allocation.

7.6 Implementation Steps & Recommended Parties

The following highlights steps toward implementation of the proposed cost allocation methodology. Several steps could occur concurrently.

- Commission further studies on State energy usage and acceptable payback periods to assess how much the State could loan using a mechanism paid back through energy consumption.
 - Several parties could potentially lead this effort, from the State Legislature to the PUC or OEP, for example.
- Develop a process to assess developer demand for transmission capacity.
 - Again, a State agency representative, the NCTC, or a transmission authority would be appropriate for this task
- Design and cost out an appropriate upgrade for the transmission system.
 - Transmission developers and renewable developers would be the primary stakeholders engaged in this process
- Develop and pass required legislation, as discussed in the subsequent section.
 - The State Legislature would need to work with the NCTC and others to craft legislation appropriate for enabling this cost allocation methodology. Authorization of bonds or appropriation of loan funds are key.
- Negotiate PPA, terms of low-debt financing, and electricity rates. File details of proposal with FERC.
 - The State would either negotiate terms directly with the renewable energy generators or through a Load Serving Entity. The New Hampshire State Energy Manager's knowledge of State office's energy consumption and expenditures

would likely come in helpful for this task. FERC and ISO-NE should also be involved early on, to ensure approval.⁸⁵

- Negotiate long-term bilateral agreements for firm transmission rights.
 - Renewable energy generators and transmission developers would need to undertake this task. Early discussions with FERC and ISO-NE would be important.
- Construct the transmission and eventually turn over operation to ISO-NE.
 - The transmission developers and ISO-NE would be engaged in this task.

7.7 Implementation Timeline

The timeline for implementation of this approach would depend on a number of factors. In particular, State load studies, budget allocations and negotiations for PPAs with renewable power developers would all need to occur. In addition, renewable generators would need to coordinate with transmission developers to negotiate appropriate transmission design and to negotiate transmission service agreements. Additional time would be needed to set up a third party, such as a transmission infrastructure authority, to facilitate negotiations should the State decide to develop such an organization.

Just as transmission projects vary in scope, the time to complete a transmission project can also vary greatly, and depends on a number of factors. In particular, planning, siting, licensing and construction are all stages in the development of transmission. As such, major transmission projects can take five to ten years or more to complete the entire process from siting to operation.

7.8 Proposed Legislative Needs

The following highlights legislative needs to move the proposal forward.

- Appropriate funds to make up-front loans (or other subsidies) to renewable developers.

⁸⁵ FERC would lack jurisdiction over a state-based proposal to provide up-front funding for the transmission enhancements, and its recovery of its investment through below-market power charges. However, both the power sale agreement and the generator interconnection agreement between the project developer and the transmission provider would be subject to FERC jurisdiction.

- Develop rules and eligibility appropriations for tax-exempt bonds. Examples exist in several states.
- Establish a transmission authority, if desired, and outline its authority and responsibilities.
- Integrate tracking of loan repayments through energy purchases. The State could make use of the existing energy tracking system in place developed to assist the State meet its goal to reduce consumption in government buildings by 10%.

7.9 Alternative Approaches

Comment [JH4]: Added new section

As an alternative to promoting renewable energy development in the North Country via direct transmission cost allocation mechanisms, New Hampshire might implement mechanisms that allow renewable energy developers to move forward with their projects after consideration of the cost of transmission enhancements for which they would be responsible. Furthermore, New Hampshire could adopt an approach that involves ratepayer funding. To limit ratepayer burden, the allocation might take an approach similar to the CAISO, where ratepayers cover the up-front costs but ultimately are refunded by renewable developers.

Alternatives to Promote Renewable Energy Development

Vermont has a program entitled the Sustainability Priced Energy Development Program (SPEED) which is intended to provide incentives for development of selected renewable energy resources. Under this program, the Vermont Public Service Board establishes default prices for a standard offer to purchase electricity from specified renewable energy resources. These default prices are above-market prices.

Power sold by developers under the SPEED program is sold to Vermont Electric Power Producers, Inc., (VEPPI) which is a state-owned corporation established for the purpose of purchasing such electricity. Electricity purchased by VEPPI is resold to each of the utilities in Vermont based on its respective load ratio share. Each of the electric utilities in Vermont is required to participate in this program. The costs of such power purchases are then passed through by each of the utilities to its retail electric service customers. The effect of this program is to spread the costs of electricity supplied by the favored renewable energy developers across all ratepayers in the state, rather than imposing the costs on customers of a specific utility. The Vermont program includes not only IOUs, but also the rural electric cooperatives and municipal utility systems.

Adoption of a program similar to SPEED program in Vermont might help to facilitate payment for the cost of transmission upgrades in the North Country. In particular, the NHPUC could set the default offer prices at a level that would be sufficient to encourage renewable energy developers to go forward with their projects after consideration of the cost of transmission enhancements for which they would be responsible. Such prices should therefore be sufficient to offset the additional costs to project developers of paying for enhancement of the Coos Loop. The effect of this program is to spread the costs of electricity supplied by developers of new renewable energy resources in Coos County across all ratepayers in the state, rather than imposing the costs on customers of a specific utility. Such an approach would align with New Hampshire's state policy to promote development of renewable energy resources in Coos County.

CAISO Approach. Though discussions with stakeholders indicated a strong preference to avoid an increase in customers' electricity rates, it is an alternative to cost allocation where the State may not be able to provide up-front loans or make direct subsidies. Furthermore, implementing an approach in New Hampshire like that in CAISO, could limit the burden on ratepayers, both by making the burden temporary and also by limiting the amount of costs covered by ratepayers. This approach would require approval by FERC. Furthermore, it would require determining which ratepayers in the State would initially cover the cost of transmission development, and whether they would initially cover the costs in part or in full.⁸⁶

⁸⁶ As a rough approximation, the potential cost to ratepayers for a transmission development cost equal to \$150 million would be an increase in electricity rates of around 0.002 \$/kWh to 0.003 \$/kWh, which would vary depending on the actual cost of transmission, which ratepayers would cover the costs, and what rates were approved to be recovered. In addition, this amount could be reduced where other partners, such as the State, private bonds or developers helped cover the transmission development cost.

Glossary of Terms and Definitions

List of Acronyms

AC	Alternating current	an electric current that reverses its direction of flow at regularly recurring intervals
ACP	Alternative compliance payments	Payments made by load serving entities subject to RPS requirements, in lieu of purchasing RECs.
DC	Direct current	an electric current that flows in one direction
FERC	Federal Energy Regulatory Commission	an independent regulatory agency within the Department of Energy that has authority over charges and terms of use of transmission lines
HVDC	High Voltage Direct Current	a high voltage DC transmission line
ISO, RTO	Independent System Operator, Regional Transmission Organization	Independent, federally regulated organizations established to coordinate regional transmission and ensure the safety and reliability of the electricity system. ISOs differ from RTOs in their status requirements.
ISO-NE	Independent System Operator of New England	operates the electric transmission system for the six New England states
kWh	Kilowatt-Hour	Measure of electrical energy
kV	Kilovolt	Measure of voltage (1 kV = 1,000 V)
NCTC	North Country Transmission Commission	created by legislature to recommend best way to upgrade or expand the Coos Loop
NHPUC	New Hampshire Public Utilities Commission	has authority over utilities in NH, limited role with transmission issues
REC	Renewable Energy Certificate	Tradable certificates indicating proof that a megawatt-hour of electricity has been generated from an eligible renewable energy resource.
RPS	Renewable Portfolio Standard	The requirement that an electricity provider generate or purchase a certain percentage of the power it supplies or sells from renewable energy resources.
SEC	Site Evaluation Committee	made up of NH government officials, has authority to approve new electric generation and transmission

Other Definitions

Distribution Lines

Power lines that take power from the transmission system to the end use customer. Distribution lines are generally lower voltage than transmission lines.

Economic Study

The legislature-mandated study of the best way to allocate the cost to expand Coos Loop to carry another 400 MW of renewable power.

Electric Load (or Load)

The amount of electric power consumed by (or delivered to) customers at specific locations on the electric grid.

Interconnection

“The facilities used to connect two power systems; those systems can be two individual control areas or between a generator and a control area.”

Minimum Interconnection Standards

The requirements for connecting new generation into the transmission lines. These are set by ISO-NE and FERC.

Power

The rate of production, consumption or transfer of electricity. It is measured in watts. One kilowatt (kW) is equal to one-thousand watts and one megawatt (MW) is equal to one million watts.

Right of Way

The legal right to use and service land along which a transmission line is located.

Transmission cost allocation

An approach to sharing costs among various stakeholders to upgrade a transmission system.

Transmission line

Take power from generation sites on the electric grid to distribution points.

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