Non-Transmission Alternatives: The Emerging Importance of Regional Planning to the Clean Energy Industry Under FERC 1000

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ABSTRACT

Traditionally, electric system plans emphasized transmission expansion over non-transmission alternatives. And, planning processes lacked serious coordination across multiple fronts: between supply and viable demand-side options; between various states along the proposed transmission corridor; and between affected utilities, communities, and other stakeholders. Such lack of coordination resulted in unduly biased system plans that favored traditional supply-side options at the expense of lower cost alternatives.

To remedy these deficiencies, the Federal Energy Regulatory Commission's (FERC) issued Order 1000 in July 2011 with the intent to help states and regions develop integrated clean energy policies across the nation. With the issuance of Order 1000, the FERC has developed a framework that has the potential to change regional planning processes, increase transparency and level the playing field between demand-side management (DSM) and supply-side resources.

According to FERC, Order 1000 will prevent undue discrimination and require transmission owners (TOs) to establish processes that provide stakeholders the opportunity to influence power system planning and incorporate state public policy requirements including Energy Efficiency (EE) and Renewable Portfolio Standards (RPS). TOs across the country are now required to develop new procedures and methodologies to incorporate state public policy requirements more directly, providing interested stakeholders additional opportunities to highlight the importance of non-transmission alternatives (NTA).

This paper discusses the potential implications of a set of reforms adopted by the FERC and the opportunities stakeholders can pursue to influence energy resource choices in their region. The paper also presents relevant case studies on existing system-wide planning processes that evaluate NTA's on a comparable basis with supply-side options. Finally, the paper illustrates a process through which both transmission and NTA solutions can be evaluated.

Introduction

Regional power planning is a complex process.[1] Ensuring reliable electric service at the lowest present value life-cycle costs requires the consideration of a diverse set of risks that could have significant impacts on a region's economy and environment over a 20 to 30 year period. Developing a coherent regional plan requires extensive coordination between multiple local distribution utilities, transmission owners, merchant generators, state and local governments, consumer advocates, landowners, and environmentalists. To date, however, planning processes have been balkanized and uncoordinated. This lack of coordination has resulted in a patchwork

[1] Regional planning in many areas of the United States is the responsibility of an Independent System Operator (ISO) or a Regional Transmission Organization (RTO).

of competing state policies that have led to periods of excess investment in transmission and uneconomic generation.

In the Northeast, and particularly in the New England ISO region, electric system plans are referred to as “Regional System Plans” or RSPs. In these RSPs, new bulk power transmission assets have historically been the focal point of the region’s evaluation of whether utilities can keep the lights on over a 20 year period. RSPs test the reliability of the bulk transmission system under two tests: transmission reliability and resource adequacy.

Under the transmission reliability test, planners evaluate the survivability of the bulk transmission system under a variety of engineering stress conditions in accordance with industry-specific standards established by the North American Electric Reliability Corporation (NERC).[2] The standard, which is enforced by FERC, generally follows the so-called N-1-1 contingency protocol; meaning that a regional power system must be able to reliably provide electricity under two contingencies that could take place one after another within 30 minutes of each other. If the test fails, additional transmission or generation needs to be built.

In addition to satisfying the N-1-1 protocol, RSPs must also address the region’s resource adequacy needs. Under this protocol, planners attempt to quantify the probability of involuntary load shedding in a population load center. Planners design the bulk transmission system to reduce the probability of involuntary load shedding to 1 day in 10 years. Resource adequacy assessments also examined the deliverability of resources at the right locations. As such, transmission analysis has been performed to make sure resources can be delivered to load centers reliably.

The development of traditional supply-side assets involves long lead times, significant risks, and complex problem solving related to design, siting, environmental compliance, permitting, and financing. Despite the complexities, RSP have typically not been well coordinated among the various stakeholders. Uncoordinated planning processes have resulted in overinvestment, especially when barriers that prevent alternative resources from entering the marketplace are left unaddressed. Given the need to deal with such complex and evolving matters, it is appropriate and prudent for local energy planners and stakeholders to actively participate in regional planning to ensure resource plans mitigate, to the greatest extent possible, these types of risks. With the issuance of FERC Order 1000, there are now greater opportunities for stakeholders to influence resource decisions and to fully integrate DSM on a comparable economic basis with traditional supply-side assets into regional resource plans.

FERC Order 1000

Prior to the issuance of FERC Order 1000, the primary venue for stakeholders to influence resource decisions was during integrated resource planning proceedings before state Public Utilities Commissions (PUCs). In many states, however, this process was less than satisfactory. DSM resources were typically accounted for as reductions to load rather than as cost-competitive alternatives to supply-side resources (i.e., transmission and utility-scale generation). As a consequence, cost-effective energy efficiency and other NTAs were steeply discounted as resources. These limitations have now been lifted in the regions of the country operating under organized electricity markets (i.e., RTO/ISO).

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[2] Bulk transmission is generally referred to as assets larger than 64kV needed to transmit wholesale electricity between utilities and/or local distribution areas.

FERC Order 1000 requires public utility transmission owners to participate, in consultation with stakeholders, in regional (and inter-regional) planning processes and produce a regional resource plan for review by the FERC. Each TO is, *inter alia*, required to amend their tariffs to explicitly incorporate the analysis of transmission needs that are driven by states' public policy requirements, such as Energy Efficiency and RPS. Additionally, each transmission owner has the affirmative obligation to evaluate alternatives to supply-side assets that may meet the needs of the region more *efficiently* and *cost-effectively*.

According to FERC, Order 1000 remedies existing opportunities for TOs to unduly discriminate against NTA resources. For example, the cost of transmission solutions must now be allocated in a manner that is roughly commensurate with benefits. This means that transmission costs may not be socialized across an entire region to the extent they have been in the past. As a consequence of FERC's Order 1000, the full cost of transmission solutions must be compared to the cost of DSM solutions which have always been borne by the customers of a specific area or state. When planners evaluate alternatives to supply-side options, transmission owners must now consider proposed non-transmission alternatives on a comparable basis with traditional supply-side options; meaning that the levelized costs of new supply will be compared to the levelized cost of DSM. Additionally, it will no longer be sufficient under Order 1000 to merely incorporate into regional plans a static amount of energy efficiency or demand response (DR) as a decrement to load. Now, varying amounts of DSM resources will need to be evaluated. Thus, the more expensive supply-side solutions become due to environmental compliance rules, for example, the greater the urgency to increase DSM investments over time to ensure energy resources are delivered at the lowest present value life-cycle costs.

Another implication of FERC Order 1000, is that TOs and regional system operators across the country will be required to refine their planning procedures and develop new methodologies to fully assess the region's bulk power system needs. Refinements include, for example, the following characteristics (Peterson et al. 2011):

- Improved forecasting techniques that estimate the impacts of energy efficiency, demand response, advanced metering initiatives, feed-in tariffs, and intermittent resources.
- Honest assessments of at-risk generation that provides for early detection of uneconomic generation due to EPA regulations.
- Expanded lists of reliability solutions able to delay, or avoid entirely, large new transmission and utility scale generation.

These changed requirements provide stakeholders with additional opportunities to highlight the importance of non-transmission alternatives. Furthermore, such requirements allow for geo-targeting resources and infrastructure in a more economical manner.

Implementation and Challenges of FERC Order 1000

But what do these federal changes mean for stakeholders at the regional level besides participating in another planning forum? The short answer is that stakeholders are now in a better position to assert that the link between economic growth and increasing electricity demand is weakening. They will be able to demonstrate that DSM is a cost-effective and reliable alternative resource that can postpone, possibly indefinitely, the need for expensive transmission upgrades and new generation. Similarly, stakeholders will be able to challenge the traditional assumption that building supply-side assets is the only solution that leads to reliability.

While the intent of Order 1000 is to enhance the transmission planning processes, there remain many unanswered questions with respect to the implementation of FERC 1000. Examples of such questions include but are not limited to the following:

- What does a regional resource plan consist of?
- What are the cost-effectiveness screening methodologies used for DSM resources?
- What DSM program plans have been developed and what level of funding has been allocated to DSM programs? Will programs be continued or have they been restricted to 4–5 years of implementation?

By fully addressing these questions before the FERC and RTOs, stakeholders can demonstrate how RSPs become regional Integrated Resource Plans (IRPs) that are better suited to satisfy multiple objectives. Such objectives include but are not limited to (Nichols, David & Hippel 2007)

- promoting national, regional, and local development objectives.
- ensuring that all households and businesses have access to electricity service.
- maintaining reliability of supply.
- minimizing the short term and long term economic cost of energy services.
- minimizing the environmental impacts of electricity supply and use.
- enhancing energy security by minimizing the use of imported commodities.
- providing local economic benefits.

In satisfying these objectives, regional plans will need to include at a minimum the following basic elements: agreed-upon planning objectives; a survey and analysis of energy use patterns; robust demand forecasts that includes the effects of DSM and plant retirements; investigation of electricity supply options; investigation of demand-side management measures including future technologies; an evaluation of multiple supply plans; evaluation of multiple demand-side management plans; an integration strategy for supply- and demand-side plans into candidate integrated resource plans; selection processes for a preferred plan based on the lowest life-cycle costs; contingency plans; an implementation strategy; and a process for monitoring, evaluating, and recreating future IRP's based on lessons-learned (Nichols, David & Hippel 2007). To the extent that an IRP fails to address the above-noted minimum threshold IRP elements, stakeholders would have a rebuttable presumption before the FERC that a transmission owner's regional plan would result in imprudent investments in supply-side assets. Similarly, if an IRP uses a cost-effectiveness screening methodology that fails to account for societal benefits or aggressively discounts the risks associated with supply-side options, then stakeholders can point to jurisdictions that follow best practices by risk adjusting avoided costs. Also, when IRPs show a tapering off of DSM investments over time, additional evidence can be presented that underscores the persistence of energy efficiency measures.

Emerging IRP Trends: Case Studies in Action

In the Northeast, stakeholders have been addressing the above noted questions for several years with varying degrees of success. As a result of their efforts, a region-wide planning paradigm is starting to emerge in New England, New York, and, at the state-level, Vermont. These lessons-learned can be applied in any region in the United States.

ISO New England

As a part of major shift in its long-term resource planning, ISO New England (ISO-NE) has started an initiative with regional stakeholders to incorporate energy efficiency and other DSM resources into its long term planning process so long as continued funding of such energy efficiency programs is assured. Previously, only energy efficiency and demand response that cleared in the Forward Capacity Auction (FCA) was included in the region's energy load forecast for purposes of transmission planning. This simplistic approach changed in 2011 when ISO-NE started to include conservative levels of energy efficiency above that cleared in the FCA. Under the new planning approach, load forecasts include the impacts of additional energy efficiency that have been based on long term potential studies reviewed by state commissions and the ISO-NE staff and actual results of fully funded programs.

Recently, ISO-NE has determined that peak load could be reduced by almost 2,000 MWs in 2021 (ISO-NE 2012). This analysis had the effect of changing the parameters of the region's approach to resource planning. Understanding that energy efficiency can have profound impacts throughout the bulk transmission system at much lower costs to society, ISO-NE is now revising its planning initiatives and pilot testing alternative solutions to transmission reliability and the resource adequacy needs of the region with geo-targeted DSM investments. In fact, ISO-NE has taken a number of steps toward evaluating NTAs on a comparable basis with supply-side options. They have developed a white paper as part of their strategic planning initiative, conducted a pilot project in parallel with a traditional transmission project, and are in the process of conducting another pilot project for assessing NTAs.

Strategic planning initiative. Like other regions of the United States, New England is evaluating the implications of retiring dozens of electric generating plants (approximately 8,000 MWs or about 25% of New England's capacity) due to changing market conditions; most are older coal plants. Some of the generating resources facing early closure are unable to cover their fixed costs from market revenues due to the removal of a floor price in ISO-NE's capacity market and low natural gas prices. Due to these changes and others, ISO-NE has identified five risks in need of further evaluation that will undoubtedly impact the region's power system over the next several years. One such risk is the misalignment of present-day market conditions with ISO-NE's current planning procedures. Due to this misalignment, ISO-NE is studying how it can reorganize the regional resource market in order to enhance the ability of market players to more fully address the reliability and resource adequacy needs of the region (ISO-NE 2011a). Proper alignment of the market environment includes, for example, the removal of barriers to entry, increased transparency and nondiscriminatory operating rules. In large part, aligning market conditions starts with advanced long-term planning for both supply-side and DSM resources, and revising market rules.

An example of how the New England market is misaligned is ISO-NE's gap between its transmission planning process and assessment of resource adequacy. This gap reflects the difference in ISO-NE's identification of resource requirements and its studies that are associated with transmission congestion and generation retirements. Resource adequacy assessments consider a probabilistic approach to regional planning, whereas the transmission planning methodology follows a deterministic methodology.

Under the resource adequacy approach, market participants bid into the power markets to ensure sufficient resources are available to serve load. This approach tends to consider zonal modeling and contingencies that could impact electric service. This process historically steeply discounted energy efficiency, as planners were unable to verify whether energy efficiency would materialize. Transmission planning takes into account a detailed system engineering analysis. Under this approach, non-passive energy efficiency has never been fully integrated into RSPs. In addition, the transmission planning horizon is 10 years as compared to resource adequacy's planning horizon for 3½ years. Since ISO-NE does not forecast beyond 3 ½ years, it keeps DSM values constant over the 3½ to 10 year horizon (ISO-NE 2011d, 38). By holding the DSM constant, ISO-NE creates a significant gap that underestimates the full potential of DSM resources. The two approaches to regional planning have resulted in a gap between the assessment of transmission needs and the market approach to ensure resource adequacy. The gap is summarized in the Table 1 below.

Table 1. Major Differences in Transmission Planning and Resource Adequacy

Description	**Transmission Planning**	**Resource Adequacy Planning**
Modeling Approach	Deterministic and detailed	Probabilistic and zonal
Load	90/10 seasonal peak[3]	Weekly distribution of peak load
Planning Horizon	10 years or more	About 3 years
Energy Efficiency	Includes EE/DR cleared in the FCA and modeled as a decrement to load after supply-side analysis is completed	

New Hampshire/Vermont NTA pilot project. ISO-NE is also conducting case studies to evaluate the potential for DSM resources to displace supply-side assets. For example, ISO-NE's Planning Advisory Committee (PAC) is considering NTAs and has provided additional information to the region's stakeholders. The PAC's evaluation provided DSM data as a supplement to the region's need assessment in the planning process. ISO-NE introduced a conceptual approach in late 2010 and undertook the New Hampshire/Vermont Pilot study (ISO-NE 2011c) as a means to include both demand-side and supply-side options. The study identified MW load reduction across all dispatch zones from viable demand-side market resources. Similarly, the analysis identified supply-side market resources necessary to reliably serve load requirements. The study, which has not yet been completed, found that more supply-side market resource requirements (i.e. MWs) were needed compared to DSM resources in order to reliably serve the dispatch zone. However, the study was limited to developing an understanding of technical issues and did not attempt to compare costs between the transmission and NTA solutions.

[3] A 10% chance that the actual system peak load will exceed the forecasted value in any given year.

Greater Hartford and Central Connecticut market resource alternative pilot project. ISO-NE has undertaken another pilot study in the Greater Hartford and Central Connecticut (GHCC) (ISO-NE 2011b). This project has been designated as a review of Market Resource Alternatives (MRA), although these are essentially the same as NTAs. This pilot study is planned to use the same system conditions and criteria for both transmission and MRAs. Importantly, the pilot study will be conducted at the same time as the transmission study, which has not always been the case. Previously, transmission studies were conducted first and DSM studies afterward. As a result of the serial nature of past planning procedures, supply-side resources were always preferred simply because such assets were analyzed first and could begin to be reviewed for actual implementation before energy efficiency was even assessed. Another aspect of the study will be to evaluate load reduction potential on a more granular basis (i.e. at specific sector distribution areas) rather than on a larger zone. This will also provide planners a more precise understanding of where to target DSM resources, and thus provide another means for treating energy efficiency on an equal basis as supply-side resources. The study results will be available by the end of 2012.

The pilot studies are expected to provide insight into how NTA/MRA options should be evaluated in concert with supply-side assessments at the regional level. These studies should be able to identify and categorize various solutions with respect to system needs and how to ensure reliable service at the lowest present value cost to consumers. The transmission solution might be cost-effective for certain needs, while NTA/MRA would be cost-effective for other situations. But both resources will be evaluated on a comparable basis. Currently, the pilot studies have been focused on analyzing the technical aspects of the integrated planning and how to incorporate various resources needs. Once comparable solutions are evaluated, cost analysis would be a part of the pilot process also.

New York Independent System Operator Comprehensive Reliability Planning Process

Even before FERC Order 1000 had been approved, the NYISO had taken significant strides toward establishing a comprehensive regional planning process wherein DSM is treated on a completely comparable basis with traditional transmission and generation resources to satisfy reliability criteria.

In summary, the NYISO's planning framework incorporates the following basic steps. As described in Attachment Y to the NYISO Open Access Transmission Tariff (NYISO 2011), the annual Comprehensive Reliability Planning Process (CRPP) begins with the development of transmission plans that are prepared, in coordination with stakeholders, by individual transmission owners. The Local Transmission Plans (LTPs) serve as inputs to the system-wide Reliability Needs Assessment (RNA). The RNA identifies violations of existing reliability criteria over a 10-year planning period and considers methods to address such violations. These criteria address both resource and transmission adequacy. A scenario analysis is performed to test the robustness of the base cases assumptions. Tests include assessments of load growth drivers, increased DSM, and resource retirements. Depending on the findings of the RNA, NYISO may issue a solicitation requesting market players and regulated entities to propose solutions to address identified reliability needs.

Due primarily to increased DSM and generation resources, the most recent RNA, published in 2010, identified no reliability needs; therefore, a solicitation was not issued (NYISO 2010). Had one been necessary, NYISO would have solicited the development of both market-based and regulated solutions – *with preference given to market-based solutions*. The responsible transmission owner and/or regulated utility must then develop a regulated "backstop" solution in the event that a market-based solution is unable to meet the state's reliability needs. Contrary to many transmission planning processes, *all* resources are considered; proposals are not limited to traditional transmission solutions. Explicitly, DSM is eligible for consideration by the NYISO. All potential solutions are considered on a completely comparable basis. Most importantly, non-transmission solutions are eligible for cost recovery under the same cost allocation principles and methodologies that govern traditional transmission solutions. This is not the case in many other regions of the country.

NYISO does not select from the market-based responses but only monitors the status of the projects on a quarterly basis to ensure that reliability needs will be met. If market-based solutions are insufficient, a regulated solution is triggered. Should both the market-based and regulated solutions be insufficient to meet reliability needs, the TOs may pursue so-called gap solutions to address immediate needs. Gap solutions are designed to be temporary and fully compatible with market-based solutions. Finally, a Comprehensive Reliability Plan (CRP) distills and evaluates all responses to determine if they satisfy the reliability needs presented in the RNA.

To date, this process has not yielded any proposed DSM solutions to reliability needs identified in the RNA. This is partially due to the fact that the last two RNAs have not identified any reliability needs due to low load growth. One shortcoming of NYISO's process, however, is that while all proposed solutions must be treated on a comparable basis, no one is compelled to produce a DSM solution; it is up to stakeholders to seize this opportunity to promote DSM as a viable alternative to traditional solutions.

Vermont System Planning Committee

FERC's requirement of transmission owners to participate in planning processes that result in comprehensive long range resource plans, in consultation with interested stakeholders, has been the convention in Vermont since 2006. Following approval of a controversial 345 kV bulk transmission line through the Green Mountains, the Vermont Public Service Board (VPSB) concluded that the state's planning processes needed substantial improvement to comply with statutory requirements involving Integrated Resource Planning (IRP).[4] In other words, the VPSB was so dissatisfied with the lack of coordinated planning among Vermont's local electric distribution utilities; Vermont Electric Power Company (VELCO), Vermont's bulk transmission owner; Efficiency Vermont; the Department of Public Service; and other interested stakeholders that it required jurisdictional parties to establish coherent and integrated processes for long term resource planning. The purpose of the VPSB's order was to never again be placed in a similar situation as in 2005 when VELCO submitted what amounted to an emergency petition. Because reliability issues were so dire at the time, the VPSB's options were limited to the selection of a transmission only solution. The limitations were the result of conventional wisdom at the time

[4] 30 V.S.A,§ 218 c A "least cost integrated plan" for a regulated electric or gas utility is a plan for meeting the public's need for energy services, after safety concerns are addressed, at the lowest present value life-cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs. Economic costs shall be determined with due regard to: (A) the greenhouse gas inventory developed under the provisions of 10 V.S.A. § 582;(B) the state's progress in meeting its greenhouse gas reduction goals; and (C) the value of the financial risks associated with greenhouse gas emissions from various power sources.

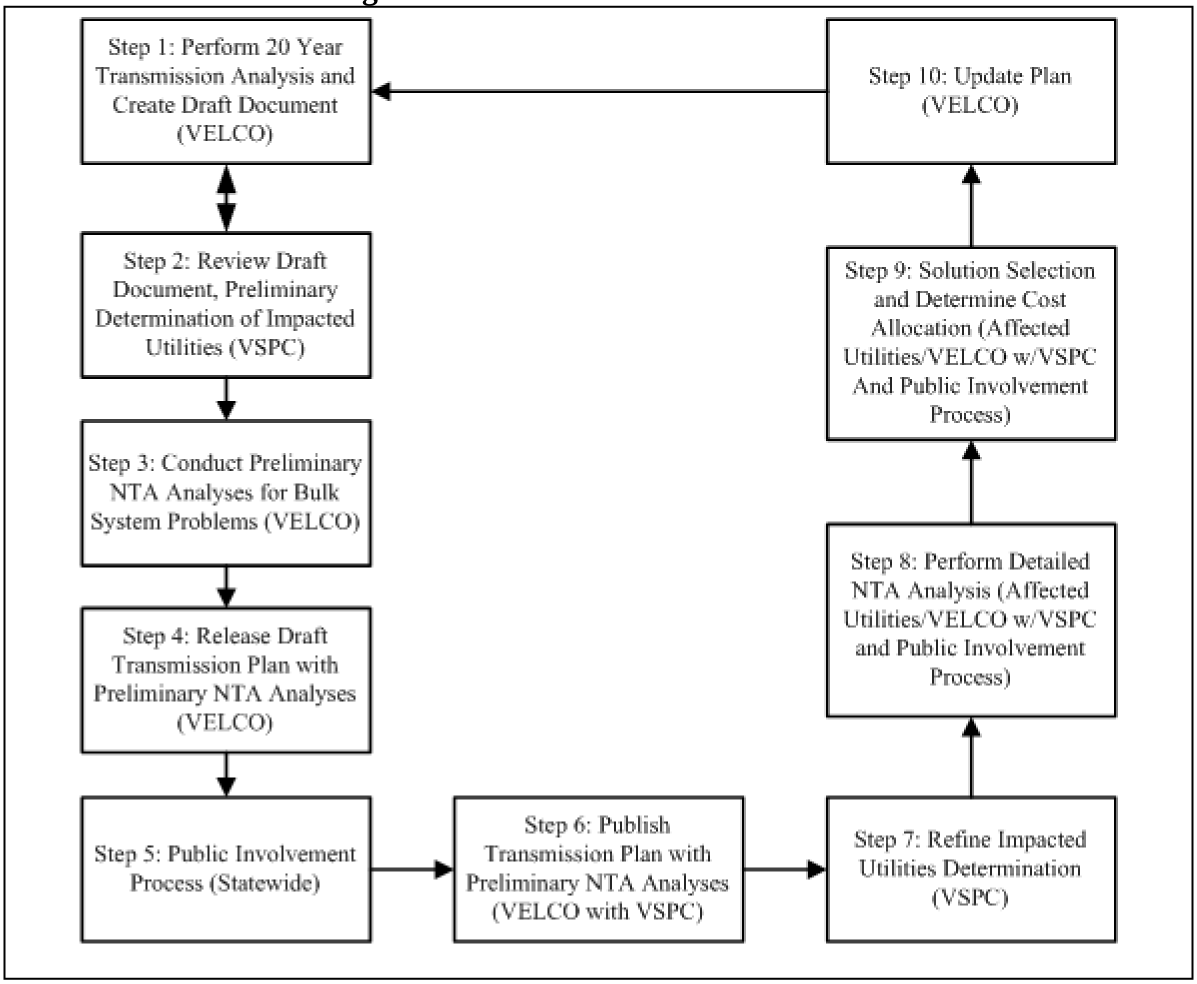
which suggested that NTAs would not have been able to cost-effectively ameliorate transmission congestion in the affected area in a timely manner.

The VPSB's conclusions ultimately resulted in the formation of the Vermont System Planning Committee (VSPC), comprised of representatives of each Vermont electric distribution and transmission utility and three public members representing the interests of residential consumers, commercial and industrial consumers, and environmental protection, respectively. The Committee and its associated planning process represented a new approach at the time to addressing energy resource reliability issues in Vermont. The VSPC process was designed to facilitate full, fair and timely consideration of cost-effective NTAs to changes in electric power demand. The Committee's objectives are to

- Increase collaboration among utilities and stakeholders.
- Lengthen the planning horizon to provide time to fully consider all alternatives on a comparable basis.
- Increase transparency of the planning process.
- Involve the public in decisions about resource planning alternatives.
- Ensure compliance with the Vermont's IRP statutes.

To fully address Vermont's energy resource reliability issues, VELCO and VSPC members create and publish a 20-year long range integrated resource plan. Before submitting a final plan to the VPSB for approval, draft plans are distributed statewide and a series of public meetings are held. VELCO and the VSPC sponsor such public engagement meetings and are responsible for responding to public comments. Non-confidential responses are subsequently posted on VSPC's website and published in the final plan. Although the resource planning process is extensive, involving up to ten major activities (and several dozen sub-tasks), VSPC's processes can be summarized in the Figure 1 below:

Figure 1. VSPC NTA Process Flow Chart



Source: VPSB 2006, 3

In developing the resource plan, VSPC members are responsible for conducting a detailed NTA analyses to compare to VELCO's proposed supply-side solution. Potential solutions are then analyzed in accordance with Vermont's societal cost-effectiveness test, which includes externality adders associated with risks and environmental damages that may be caused by supply-side resources. Analysis of all potential resource solutions includes an evaluation of a host of factors including but not limited to

- The relative rate and bill impacts on Vermont consumers, assessed on a life-cycle basis over the life of each alternative.
- The relative financial feasibility of each alternative, including credit rating impacts on VELCO and local distribution utilities.
- The ability of each alternative to be implemented in timely manner to address the Reliability Deficiency, including but not limited to issues relating to siting, local environmental impacts, obtaining necessary property rights, securing required governmental approvals, and existence of or necessity to construct supporting infrastructure.
- The relative economic benefits to the state, including access to other power markets.

- Other significant relevant costs and benefits particular to the set of alternatives under consideration.

Selection of preferred solution. After completing its analysis of alternative solutions, the VSPC's final planning process step is to select a preferred solution within two years of the release of the draft plan and notify the VPSB, ISO-NE and the public of its selection. Along with its notification, the VSPC also submits a strategy for implementing its plan to document how its preferred solution ensures the reliability of the state's electric grid.

As part of this planning process, VELCO and each affected local distribution utility have also agreed to assess and allocate the costs of alternatives in a similar manner. For example, benefits of NTAs include the use of the same avoided costs applicable to the statewide energy efficiency programs at the time of the NTA analysis. Additionally, VELCO and each affected local distribution utility agree to use the same externality adders and risk factors for purposes of the NTA and transmission analyses.[5] And, most importantly, VELCO and each affected local distribution utility agree to apply the same cost allocation procedures. Such cost allocation procedures ensure that the VSPC analyses of alternative solutions are performed on a comparable basis. Vermont's cost allocation and analytical procedures are subject to the following rubric:

> *If the DSM project, for example, defers or avoids the construction of transmission facilities whose costs would have been shared among all the local distribution utilities, the verifiable costs of the DSM project shall be allocated to each local distribution utility in the same fashion as the costs of such avoided Transmission facilities would have been allocated by tariff if such Transmission facilities had been constructed* (VPSB 2006).

Conclusion

Recognizing that existing planning processes were inadequate, planners in the Northeast have changed their planning methods and developed new planning frameworks that are similar to the methods and frameworks highlighted in FERC Order 1000. In reviewing ISO-NE's, NYISO's and Vermont's planning processes, it is now apparent that regional planners in the Northeast consider NTA solutions to be viable, cost-effective resources that can go a long way toward reliably meeting regional power needs. They are evaluating all solutions on a comparable basis by allowing resource levels to compete on costs. To this end, Northeast planners are moving quickly toward putting in place procedures that are unbiased toward any proposed solution. This is the intent, if not the spirit of FERC Order 1000. Each proposed resource solution is tested on its merits. Northeast planners have also realized that DSM resources are reliable based on actual and verifiable results. Further, Northeastern regional planners are committed to sustaining demand-side resources over the long term and are dedicated to continuously improving DSM programs. Continuous improvement includes discovering new cost-effective energy efficiency potential despite years of program implementation and constantly evaluating the delivery of efficiency programs. Such changes can be applied in any region of the United States.

[5] Each of these agreed upon inputs are subject to a rebuttable presumption clause in a related Memorandum of Understanding.

Despite the progress that has been made in the Northeast, the allocation of costs (outside of Vermont) for NTA resources has not yet been determined. Planners have only the FERC's cost principle (i.e., costs shall be roughly commensurate to the benefits) to guide them in their analysis of attributing benefits and costs associated with the development of new resources.
In the section below, we propose a two part planning process which summarizes the case studies noted above and may allow for the development of a sound cost allocation procedure. In accordance with the two-part planning process, resource planners should include processes that equally consider both transmission and NTA solutions for satisfying the region's reliability and resource adequacy tests noted above. To develop such a planning process, the following steps are appropriate:

- Forecast EE/DR for a longer horizon coinciding with transmission planning horizon.
- Consider EE/DR that has been cleared in FCA as well as EE/DR resources included in state/other sponsored initiatives (i.e., state public policy requirements).
- Continuously estimate additional cost-effective potential EE/DR in the region.
- Develop a database where amounts of annual incremental and cumulative EE/DR can be registered and evaluated.
- Use the database during the regional need analysis to refine load forecasts, transmission reliability and resource adequacy.
- Compare the costs of transmission and NTA solutions on a comparable basis.

As a regional plan is developed, it is imperative that the creation of NTAs is completed in parallel with the development of transmission-only solutions. Such a dual track process ensures that the benefits and costs of both options can be evaluated on a comparable basis and that no resource is unfairly discounted. Also, the impacts of EE/DR resources need to be analyzed over the same time horizon as transmission; meaning a minimum of 10 years. Further, as required by Order 1000, the cost of transmission solutions must now be allocated in a manner that is roughly commensurate with the benefits. This will have the effect of leveling the playing field between DSM and supply-side resources as transmission-only beneficiaries will be responsible for ever greater proportions of supply-side costs; making DSM a more coveted cost saving resource.

Finally, with the issuance of Order 1000, the traditional analytical framework has been replaced. Transmission owners and regional planners are now required to adopt a new approach to transmission planning. The new approach provides stakeholders a new venue to argue for the full consideration of NTA solutions to supply-side assets and to influence regional resource decisions.

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