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About the Author

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Executive Summary

Non-Transmission Alternatives (NTAs) are electric utility system investments and operating practices that can defer or replace the need for specific transmission projects, at lower total resource cost, by reliably reducing transmission congestion at times of maximum demand in specific grid areas. NTAs can be identified through least-cost planning and action, one geographic area at a time, for managing electricity supply and demand using all means available and necessary, including demand response, distributed generation (DG), energy efficiency, electricity and thermal storage, load management, and rate design.

The Federal Energy Regulatory Commission (FERC) targeted NTAs in Orders 890 and 1000, requiring regional transmission planning processes which are open, transparent, and coordinated, and which provide opportunities to review NTAs on a comparable basis to transmission infrastructure.

NTAs are important because they can be lower-cost options that simultaneously support multiple goals and objectives for 21st Century infrastructure. For example, NTAs can offer:

- affordability and lower cost,
- higher efficiency because some distributed technologies can be integrated, and synergistic;
- reliability, redundancy, and resilience;
- risk-reduction for a number of known system challenges and risks;
- environmental protection, especially with lower greenhouse gases and hazardous emissions and lower water consumption; and,
- possibly also social benefits, such as increased job creation and retention.

In several locations around the U.S., lower-cost NTAs are already proving capable of deferring or displacing some needs for higher-cost transmission projects. Thus, there is growing interest about NTAs in state public utility regulatory commissions and among other interested parties. Important questions being addressed include:

- What are the technical and economic potentials for NTAs?
- Are there any particular identifiers, in the course of transmission and integrated resource planning, of important opportunities for NTA analysis?
- Who might be responsible for modeling and planning NTAs, and what will be procedures for bringing information about possible NTAs into the relevant utility planning process(es) at either the state or regional levels?
- How should potential developers plan, seek approval for, and implement NTAs?
- What are the appropriate venues for NTA planning and approvals?
- Are there appropriate roles for regulated utility companies in NTA analysis, design, operations, and management, or should third parties and customers assume those roles?
- How can system operators be certain that NTAs will prove at least equivalent to and as reliable as the transmission options they might postpone or replace?

- How will NTA cost recovery and cost allocation be handled?

This paper introduces and explores the subject of NTAs. In Part I, NTAs are defined and their potential roles in transmission planning processes are described, as they are currently defined by FERC Orders 890 and 1000, and as NTAs could be included in state or utility integrated resource planning (IRP). Part I also itemizes and reviews the reasons for considering NTAs, which include cost savings, alleviating transmission siting concerns, and possibilities for NTAs to increase system reliability and resilience and to provide positive synergies by co-locating infrastructure and better integrating infrastructures and services, primarily for: (a) consumer energy use; (b) electrical and thermal energy supplies, demands, and utilization; and (c) combined energy and water infrastructure.

Next, challenges associated with NTAs are reviewed and summarized. Three major challenges are identified: (1) modeling and demonstrating equivalence to transmission options; (2) cost recovery and cost allocation; and (3) potential misalignments with traditional electric utility business models and regulatory regimes.

Part II briefly reviews existing state policies and regulatory actions related to NTAs and proposes some preliminary options for state regulators to consider, for instigating and perhaps institutionalizing NTA modeling, planning, and implementation. Only two states, Maine and Vermont, have passed legislation that is directly related to NTAs: Maine's law directs the state regulatory commission to determine whether it is in the public interest to designate a smart-grid coordinator, whose functions could include NTA development and operations, and Vermont's law obligates the utility or other transmission provider to undertake NTA analysis. Several other states and the Bonneville Power Administration have also taken actions supporting NTA modeling and development. Part II includes brief descriptions of those actions. In addition, many states have program requirements and incentives that focus on some of the specific components that might make up NTAs, such as energy efficiency, demand-response, load-management, DG, and storage.

Next, Part II summarizes options that state utility commissions can consider for supporting NTA modeling, planning, and implementation. Options include:

- reviewing existing rate designs and utility compensation incentives to check how they affect different NTA resources;
- reviewing authorities and previous regulatory decisions to determine whether any changes are needed to facilitate differential service charges, by grid location, in support of NTA development;
- reviewing and understanding how NTAs might complement, or conceivably conflict with, existing state regulatory policies and practices;
- identifying one or more specific transmission projects for consideration, and inviting interested parties to propose NTAs;
- coordinating electric utility planning with local governments and communities; and,

- for states with restructured electric utilities, including provisions for the support of NTA development, such as energy efficiency and renewable or clean energy standards, in requirements for standard offer service.

Part III concludes with the idea that FERC efforts to establish "comparable consideration" of NTAs could be less than fully effective, primarily because of the absence of any mechanisms for NTA cost-sharing. Even so, FERC's efforts to institutionalize NTA analysis could prove to be a most important first step towards developing NTAs, and it appears that states have multiple opportunities to advance cost-effective NTAs through existing IRP and certificate of need proceedings. With the possibility that NTAs could produce cost-savings for utility customers, it is worth some effort to enhance existing state procedures, or even develop new ones if necessary, to ensure opportunities for NTAs to compete.

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I. Introduction and Background

A. What are non-transmission alternatives and what is their possible role in electric utility planning and operations?

A non-transmission alternative (NTA) is any combination of equipment and operating practices that is capable of deferring or replacing the need for a specific electric power transmission project, by reliably alleviating transmission congestion in a specific area. Welton (2014, p. 7) explains, an NTA is "any resource or configuration of resources that can replace or delay the need for additional transmission." In its FERC tariff, Public Service Company of Colorado (2012, Attachment R, ¶H., p. 22) states:

> Non-transmission alternatives include, without limitation, technologies that defer or possibly eliminate the need for new and/or upgraded transmission lines, such as distributed generation resources, demand side management (load management, such as energy efficiency and demand response programs), energy storage facilities and smart grid equipment that can help eliminate or mitigate a grid reliability problem, reduce uneconomic grid congestion, and/or help to meet grid needs driven by public policy requirements.

As Hempling (2013, p. 4) describes it, an NTA is "[a]n alternative to transmission service… not transmission service… [but] a substitute for transmission service."

NTAs are explored through integrated resource planning (IRP) for a particular geographic area, considering any and all means available for managing electricity supply and demand. NTAs might be comprised of various combinations of utility rate-making designed to induce specific customer responses, along with geo-targeted energy efficiency, load management, demand-response, DG, and storage. NTAs are also sometimes called "non-wires," "market-based," or "market resource" alternatives (Bonneville Power Authority, 2014; Frayer and Wang, 2014). These terms reflect the fact that many of the components that could be deployed in an NTA are demand-side options or supply side options that require customer participation; in many jurisdictions wires solutions are the purview of regulated utility companies but non-wires solutions often require customer participation, which is often initiated by one or more market-based alternatives.

The Federal Energy Regulatory Commission set the stage for NTA analysis through its Orders 890 and 1000. In those Orders, FERC sought to "standardize[] transmission providers' planning requirements, and… open the transmission planning process to all interested stakeholders and potential customers." FERC required planning to be open and transparent, coordinated and regional, accounting for both economic and reliability concerns, and with costs allocated fairly among participants. (Davis, 2013, pp. 22-24). Most important for the purposes of this paper, FERC directed "[t]ransmission providers [to] identify how they will treat resources on a comparable basis, and… identify how they will evaluate and select from competing solutions to ensure comparability" (Davis, 2013, p. 23, footnotes omitted).

The North American Electric Reliability Corporation (NERC) is responsible for developing transmission planning standards, subject to FERC approval. NERC has already developed a set of transmission planning standards, including Standard TPL-001-4 (NERC, 2005-2014). The purpose for this standard is to:

> Establish transmission system planning performance requirements… to develop a bulk electric system (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable contingencies (NERC, 2005-2014, p. 1).

This standard explains the basic requirements that must be met by each designated transmission planner and planning coordinator. The standard covers: (R1) the kinds of modeling capability that must be maintained; (R2) what factors are to be included in annual modeling exercises; (R3) the basic types of studies that shall be completed; and (R4) what types of contingency analyses are required. In addition, the rule discusses information sharing with adjacent planning coordinators (in R8) and requirements for an "open and transparent stakeholder process" (in Attachment I). In general, a result of transmission planning is to identify a list of contingencies that would violate reliability criteria, and then develop corrective action plans which "[l]ist system deficiencies and the associated actions needed to achieve required system performance." Furthermore, the standard states that corrective action plans shall "[b]e reviewed in subsequent annual planning assessments for continued validity and implementation status…" (R2.8).

NTA analysis enters this picture as a means for developing an alternative corrective action plan, for deferring or replacing (that is, substituting for) one or more transmission options. Readers should bear in mind, however, that "FERC's Order 1000… does not establish any requirements as to which [market resource alternatives (MRAs)] should be considered or what the appropriate metrics [would be] for evaluating MRAs against transmission solutions" (Frayer and Wang, 2014, p. 15).

B. Reasons for considering NTAs

The primary reason for considering NTAs is that any NTA that is successful at deferring or replacing the need for a transmission asset would be a lower cost means of meeting the utility system requirements. That is axiomatic: If comprehensive modeling does not show that an NTA would be both lower cost and functionally at least equivalent to the otherwise selected transmission option, then the NTA would be rejected. In addition to the direct possibility of cost savings, though, there are some specific reasons for considering NTAs that are most directly associated with transmission planning activities:

(1) NTAs can alleviate or reduce energy infrastructure siting concerns, compared to often-contentious transmission siting.

(2) NTAs can help democratize energy infrastructure planning decisions by more fully engaging customers and their agents in planning decisions.

In thinking about these two issues, Sovacool and Dworkin (2014, Chapter 6) explore due process and procedural justice concerns. They ask,

> When should the state be able to exercise eminent domain and expropriate land for energy projects? And, at what point do we as a society consciously and deliberately require individual interests and rights to suffer for a greater public good?

Transmission lines raise exactly these questions, and NTAs can offer some relief, because at least some of the components that might comprise an NTA involve consumer decisions and localized infrastructure that need not invoke eminent domain concerns. Sovacool and Dworkin suggest possible approaches, such as participatory decision making including broad public involvement. NTAs are not a panacea for addressing these concerns, but NTA modeling and planning does provide opportunities for localized discussions about possible energy futures and could engender increased public involvement in decision making.

(3) NTA development could happen relatively quickly, fast enough to defer some transmission projects and conceivably supplant others.

(4) NTAs could also be developed gradually, organically and incrementally, in conjunction with ongoing changes in consumer demand.

These two qualities are also related. Transmission line development can easily take several years for all approvals, siting, and construction. During the delays between the time that a need for a transmission improvement is identified and when it can be completed, at least some NTA components can be developed and operated, providing a chance for NTAs to demonstrate their capabilities. It is also possible that NTAs might avoid investments in assets that could prove to be strandable in the future, depending on what happens with trends towards flat or even declining consumer electricity use, a growing prevalence for DG, and improvements in energy storage capabilities and cost-effectiveness. Thus, NTAs can produce positive option value compared to transmission investments that tend to be more lumpy.

(5) NTAs can generally increase diversity and reduce risks, thus likely providing higher reliability and resilience.

(6) NTAs can produce synergies from integrating and co-locating infrastructure, including for example by co-locating and functionally combining electric, thermal, and water systems infrastructures, such as by deploying combined heat and power systems and distributed energy and thermal storage.

In addition to those six potential benefits, NTAs can provide associated non-transmission economic and environmental benefits (Hempling, 2013, p. 7; Watson and Colburn, 2013, p. 37; Welton, 2014, p. 36).[1] Examples can include reduced emissions, reduced water consumption, and increased local employment creation and retention. Realize, too, that many NTA components can prove fully cost-effective on their own right, even before accounting for transmission benefits. Examples include energy efficiency, demand-response, and load management where avoided energy and generation capacity costs are often sufficient to result in positive value.

C. Challenges associated with NTAs

Watson and Colburn (2013) review FERC Order 1000 to explore how well the resulting planning structure addresses NTAs. They identify some major barriers, which they conclude are preventing transmission planning processes from identifying and then implementing "the most efficient and least-cost transmission system" (Watson and Colburn, 2013, p. 37). The barriers to NTAs they identify include:

> (1) No ready source of funding or cost allocation methodology…;
> (2) No entity is obligated to propose or implement non-transmission solutions…; [and]
> (3) NTAs provide benefits that extend far beyond reducing the need for investment in transmission… benefits [that] are not valued in [transmission] planning (Watson and Colburn, 2013, p. 37; see also Warren, 2013, pp. 144-5).

Similarly, Welton (2014, p. 6) finds that the current transmission process "suffers from bias and skewed incentives." And, Hempling (2013, p. 2) identifies major "gaps" in FERC Order 1000 compliance "between FERC's aspirations and industry practice." Those gaps include:

> (1) [A] transmission provider does not have an independent obligation to search for and assess alternatives…;
> (2) There is disagreement over whether the procedures for considering NTAs, as submitted by the regions, will ensure 'comparable consideration'; [and]…
> (3) [C]ost recovery: If a transmission proposal serves regional needs, the provider can allocate and recover the costs regionally through a FERC-jurisdictional tariff… [but] [t]here is no comparable opportunity for regional cost allocation of an NTA because an NTA, by definition, is not 'transmission' subject to FERC jurisdiction.

Both Watson and Colburn (2013, p.40) and Hempling (2013, pp. 9, 11, 13, 15, 17) question whether utility rates can be "just and reasonable" if NTAs are capable of providing equivalent, lower-cost services, but are not implemented.

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[1] For a comprehensive review of potential benefits from distributed energy resources, see Lovins and Rocky Mountain Institute, 2002.

As Watson and Colburn (2013, p. 37) report, early successes in NTA implementation rely heavily on what can generally be considered to be market-based alternatives, which can demonstrate low-costs and positive life-cycle benefits; that is, market-based alternatives with total benefits greater than total costs and which include at least some benefits due to deferring or replacing the need for transmission investments. Those few early successes do not prove, however, that NTAs will regularly fill all opportunities where they might prove to be cost-effective. As Frayer and Wang (2014, p. 59) point out, by late 2014 experience in seven regional transmission operator (RTO) planning processes shows two RTOs with no NTAs studied, two with NTAs considered but transmission options selected instead, and three with ongoing reviews but no NTAs selected to date.

Transmission planning organization compliance filings for FERC Order 1000 highlight these ongoing challenges for NTA modeling, planning, and implementation. A first major challenge is in determining where the responsibility might lie for ensuring NTAs are included in modeling and planning. Transmission planning procedures allow interested parties to request studies and to propose NTAs, but do not have any mechanisms to require NTA analysis.

1. NTAs present challenges for modeling and demonstrating equivalence to transmission options

NTA modeling presents significant challenges for utility planners for two major reasons. First, since the mid-20th Century, utility planners traditionally focused more attention on top-down modeling of centralized generation and high-voltage, long-distance transmission, with less attention to bottom-up planning about how best to manage demand and how to optimize distribution system resources. The tendency has been to treat consumer demand as a given, and then use the two primary tools of central station generation and transmission, to meet those demands. Planning for utility distribution system O&M and capital expenditures has traditionally been the purview of a utility working group that is separated from and not fully integrated with utility integrated resource planning. This reflects separate silos that still remain in the structure of many electric utilities. For all those reasons, utility integrated resource planners are generally more familiar with central station generation and transmission options, and can find it difficult to model and plan for NTAs. It is also likely that utility planners are not as ready to rely on the less known and less proven capabilities of NTAs, compared to transmission options. (GDS Associates, 2007, pp. 5-7).

These tendencies are gradually changing – with increasing attention directed to changes in customer demand, energy efficiency, demand-response, and DG – but important modeling challenges remain.

One challenge, identified by Energy and Environmental Economics (2012, p. 12) is for NTA analysis to begin early in the transmission planning process, "when the transmission need is just beginning to become visible to transmission planners." The early start is important both because of the long lead times needed to plan, permit, and construct new transmission lines and because some NTA resources can trigger needs for detailed geo-targeted prospecting and could sometimes identify NTA resources requiring long lead times. In contrast, some of the FERC Order 1000 compliance filings describe procedures where transmission solutions are identified, modeled, and proposed first, and NTA proposals are invited afterwards (e.g., OATT Attachment K filings from: Florida Power & Light, Docket ER13-00104-000; ISO New England, Docket ER13-00193-000; and PJM Interconnection, Docket ER13-00198-001). The New England *Regional Framework for Non-Transmission Alternatives Analysis* (New England States Committee on Electricity, 2012, p. 3) is intended to help solve this problem by conducting transmission and NTA analyses in parallel.

In any case, work is needed to ensure that utilities and interested parties will have access to tools that are capable of modeling with sufficient accuracy the many potentially useful components that can serve NTA purposes, including energy efficiency, demand response, load management, DG, and energy and thermal storage. Frayer and Wang (2014, p. 9) propose, "The analysis should be sufficiently detailed and comprehensive so as to distinguish between the feasible solutions' traits and defining characteristics and benefits." At the same time, however, the tools need to be simple and easy enough to use to gain insights at reasonable cost. Stadler et al. (2014), Hirvonen et al. (2014), and Manfren et al. (2011) report on some of the complexities involved in modeling NTAs and explore over a dozen computer models that are available for analyzing investment options for individual buildings and clusters of buildings. As Wang and Poh (2014) report, though, there is no universal agreement on the modeling techniques to use for the purpose of evaluating NTAs. Another aspect of modeling concerns is identified by Watson and Colburn (2013, p. 37) and Welton (2014, p. 37), who report that transmission planning authorities could tend to limit their consideration of NTA benefits only to transmission-cost deferment, without necessarily including other distribution system and customer benefits.

Pearre and Swan (2015) explore the kinds of regional and local information planners might need to specify electricity storage technologies. As Pearre and Swan (2015, p. 502) explain, a simple "scoping and viability" tool is needed, so that planners can quickly and easily: (a) identify and quantify system needs; (b) compare system needs with the different capabilities of each major type and size of energy storage technology; (c) decide which technologies to subject to more complete power flow modeling; and (d) estimate the expected costs of meeting system needs using various combinations of the available technologies. But, Pearre and Swan (2015, p. 509) employ several "simplifying assumptions" that highlight existing modeling limits. For example, they model storage as if it provides only a single service, instead of multiple services that particular technologies could be capable of delivering.

Regardless of progress being made in modeling distribution systems and the effects of individual and combined NTA components, planning capabilities eventually need to be sufficiently valid and robust so that modelers can determine with adequate precision that an NTA will be capable of providing the same or more benefits, compared to a given transmission option. As GDS Associates (2007, p. 7, emphasis in original) report, NTAs "*must* be designed to have no negative impact on reliability." Frayer and Wang (2014, pp. 8-9) question whether NTAs can be fully comparable to transmission alternatives, in terms of the magnitude and breadth of benefits they can provide, their operational certainty, and the comparative life-span of NTA components as opposed to transmission assets. Frayer and Wang (2014, p. 8, emphasis in original) discuss this issue in the context of "market resource alternatives" (MRAs):

MRAs are increasingly being put forth as possible solutions *in lieu* of transmission infrastructure. However, based on the characteristics of MRAs today, MRAs are rarely a complete substitute to transmission, and individual MRAs typically provide only a partial suite of the services that transmission provides. Nevertheless, MRAs (either individually or in combination) can provide specific benefits and can serve as complements to transmission, and vice versa. Furthermore, MRAs have the potential to delay the timing for needed transmission investment. An understanding of what services MRAs can and cannot provide, and the benefits and challenges associated with MRAs is therefore critical for system planners, who must ultimately be able to evaluate viable MRAs and transmission projects side-by-side and select a solution that best addresses the needs of the electric power system and customers.

In addition to the challenges associated with how to perform NTA analysis, is the question of who will model and propose NTAs. FERC Order 1000 provides the opportunity for NTA analysis, but no mechanism to ensure that NTAs are included. FERC assumes that some participants will model and propose NTAs for consideration, but FERC does not make clear who such participants might be, nor where the resources will come from to pay for the necessary modeling (Hempling, 2013; Warren, 2014, pp. 144-5; Watson and Colburn, 2013; Welton, 2014). Some of the FERC Order 1000 compliance filings relay the expectation that the existing transmission owners themselves will be the entities proposing NTAs (e.g., Florida Power & Light, Docket ER13-00104-000; Louisville Gas & Electric Company and Kentucky Utilities Company, Docket ER13-897-000). Another major assumption in some FERC Order 1000 compliance filings is that states can require the development of NTA components, which will then be incorporated into regional transmission planning (e.g., ISO New England, Docket ER13-00193-000; Southern Company Services, Docket ER13-00897-000).

2. NTAs present challenges for cost recovery and cost allocation

Cost recovery is challenging because some NTA functions can be accommodated in wholesale transmission markets but others will rest with retail electricity markets. Some NTA functions do provide transmission services, such as ancillary services and some electricity storage capabilities, and DG in wholesale markets. Others do not function in transmission markets, such as energy efficiency, and DG in retail and net metering markets. In addition, demand response, although capable of delivering some ancillary services, is presently in limbo because of the recent federal court ruling on FERC Order 745.[2] (Hempling, 2013, pp. 4-5, 17).

Cost recovery is also at issue because FERC has authority to provide for cost allocations and cost sharing for transmission projects, but has only a limited authority over cost allocation for NTAs. The current situation is that transmission expenses can be assigned to all who benefit from the transmission, along the whole transmission path, but an NTA at a particular location does not have a clear path to sharing costs with all who might benefit from deferring or abstaining from developing a transmission asset. This is not an insurmountable obstacle for

[2] Elec. Power Supply Ass'n v. FERC, --- F.3d ----, 2014 WL 2142113 (D.C. Cir. May 23, 2014).

NTA resources that pay for themselves through avoided retail utility costs, such as energy efficiency, but could leave unfunded other NTA resources that can produce transmission-avoidance benefits but have no identifiable source of funding. As Welton (2014, p. 50) explains, the present lack of any path to regional cost allocation leaves a process with a "transmission-first culture." The process, she (Welton, 2014, p. 39) says,

> effectively renders non-transmission alternatives infeasible, by denying non-transmission solutions a viable source of regional financing. No developer will propose a non-transmission alternative financed only by its customers, when much of the non-transmission alternative's benefit comes from its role in filling a regional transmission need. In contrast, developers will have ample incentive to put forth proposed transmission projects—even if less efficient and effective than a non-transmission alternative—given the guarantee that, if selected in a regional plan, costs will be apportioned among beneficiaries.

Hempling (2013, p. 19) calls this situation an "unavoidable problem." He explains, "If a state-regulated load-serving entity has to bear 100% of the NTA cost, and that amount is greater than the state's share of a regionalized cost of the transmission project, the… state commission would not likely approve full cost recovery… ." The one exception is in New York State, where the New York ISO provides for cost recovery for "regulated non-transmission reliability projects… in accordance with the provisions of New York Public Service Law, New York Public Authorities Law, or other applicable state law" (Docket ER13-00102-000, ¶ 31.5.1.6 and 31.5.6.3).

3. NTAs challenge traditional electric utility business models and existing regulatory regimes

Because they rely in part on customer-side options and on technologies that can reduce the need for traditional utility capital expenditures, NTAs can be perceived as a threat to a utility's business model. Thus, NTAs are related to ongoing discussions, and multiple proposals for regulatory and legislative approaches and initiatives, about how best to align a healthy financial future for regulated utility companies, while working towards achieving the lowest-cost utility system.

When an NTA is selected for implementation a primary reason will be that the NTA costs less than the transmission option, thus reducing a utility's opportunity to invest in the transmission option and earn a return on that larger investment. In addition, not all NTA expenditures lead directly to utility earnings. Some, like energy efficiency improvements, will tend to decrease utility sales and earnings and others will sometimes provide opportunities for non-utility investments and earnings.

In addition, it should be understood that implementing some NTA options could require changes in existing regulations. Examples might include: changes to interconnection rules that will enable intentional islanding in microgrids; rules enabling multiple customers to share electric and thermal energy produced through combined heat and power systems (as reviewed by Hirvonen et al., 2014); and possibly differentiating rates and services geographically, while still adhering to the regulatory principle of no undue discrimination. Regulators could also find challenges in determining appropriate ownership options and providing appropriate incentives for NTA developers and operators, including incentives for utilities associated with: (a) reduced capital investment opportunities; and (b) reduced sales resulting from increases in energy efficiency, DG, and possibly fuel-switching measures.

II. Next steps for NTAs: Options for State Regulators

Evans and Fox-Penner (2014, pp. 51-53) prescribe a two-pronged approach for planning and implementation that involves both transmission and central station grid assets along with what could be non-transmission assets such as microgrids, CHP systems, and batteries. Evans and Fox-Penner (2014, p. 53) explain, "[O]ptions can be optimized only within a framework of portfolio analysis, with clearly designated objectives and a deep understanding of the benefit streams flowing from each option." This paper represents an early, modest attempt to explore what that framework might look like and propose incremental steps that state public utility commissions might take to lead towards the objective of optimizing portfolios.

A. Several states are already taking steps to facilitate NTA modeling, planning, and implementation.

Two states have explicitly addressed NTAs through legislation. Maine's law directs the state regulatory commission to determine whether it is in the public interest to designate a smart-grid coordinator, whose functions could include NTA development and operations.[3] Vermont's law obligates the utility or other transmission provider to undertake NTA analysis as part of the transmission planning process.[4] In these and other jurisdictions, actions supporting NTAs are underway. These include:

- Since 2001, Bonneville Power Administration (BPA) has been engaged in a system-wide initiative for modeling and planning "non-wires solutions" for its service territory in the Pacific Northwest (GDS Associates, 2007, pp. 10, 12). Two projects are highlighted on the BPA web site (2014). Neither of these projects appears to be capable of fully displacing the need for planned transmission improvements, but both are reported as including some fully cost-effective solutions that are capable of deferring the transmission infrastructure needs by as much as several years (Energy and Environmental Economics, 2011 and 2012).

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[3] *An Act to Create a Smart Grid Policy in the State* ("*Smart Grid Policy Act*") (P.L. 2010 Ch. 539 codified at 35-A M.R.S.A. § 3143 (2010)).

[4] 30 Vermont Statutes Annotated, §218c(d), http://www.leg.state.vt.us/statutes/fullsection.cfm?Title=30&Chapter=005&Section=00218c. Vermont also directs the state's utilities and Public Service Board to advocate at FERC and NEPOOL for consideration of NTAs in the planning process, Public Act 61, § 8 (2005 Vt., Bien. Sess.), http://www.leg.state.vt.us/docs/legdoc.cfm?URL=/docs/2006/acts/ACT061.htm.

- California (CEC, 2005) adopted an energy action plan in 2003 which includes a "loading order" for energy resources, preferring energy efficiency, demand response, renewable resources, and clean distributed resources. The California Public Utilities Commission (CA-PUC, 2014b) has directed the state's investor-owned utilities, community choice aggregators, and electric service providers to procure more than 1.3 GW of cost-effective energy storage by 2020, to be procured in phases every two years starting in 2014, and to be installed and operational by the end of 2024. The storage resources procured will include facilities that are variously transmission-connected, distribution-connected, and customer-side applications. The storage mandate is also designed to allow for multiple ownership models and a wide variety of energy storage "use cases," including for example providing ancillary services, peaking power, distribution system deferral, and load shifting. California (CA-PUC, 2014a) has also initiated a rulemaking for utility distribution resource planning.

  In California, Pacific Gas & Electric, the Clean Coalition, and other partners are presently developing a Hunters Point Community Microgrid project, for an area serving about 20,000 customers in the southeastern San Francisco (Clean Coalition, 2014). Preliminary plans call for over 30MW of solar PV, and modeling is being developed to simulate deployment of advanced inverters and electricity storage.

- Connecticut (CT-DEEP, 2014) has established a microgrids grant and loan program, to support high-reliability energy systems for critical public facilities. Grants were provided in a pilot round, to provide assistance to Connecticut municipalities for the cost of design, engineering services, and interconnection infrastructure. About a dozen projects have been selected to receive grant funding. When developed, microgrids capable of operating in intentional island mode will provide energy to various public facilities, such as police and fire stations, emergency operations centers, and public shelters including school buildings.

- Hawaii PUC has directed the Hawaiian Electric Companies (HECO Companies) to develop and implement action plans "to aggressively pursue energy cost reductions, proactively respond to emerging renewable energy integration challenges, improve the interconnection process for customer-sited solar photovoltaic (PV) systems, and embrace customer demand response programs" (HI-PUC, 2014a and 2014b).

  In Hawaii, a microgrid project called "Paniolo Power" is under development by a private owner, the Parker Ranch on the Big Island (Paniolo Power, 2014). This project results from an integrated resource plan undertaken by the Parker Ranch along with Siemens and Booz Allen Hamilton. The plan includes both the Ranch and surrounding communities. Though this project is not explicitly described as an NTA, the initial IRP calls for Paniolo Power to eventually produce a total of about 90MW, which is expected to be sufficient to serve about 75% of the total requirements on the western side of the Big Island. Plans under consideration include combining wind power with pumped-storage hydro.

- Maine Public Utility Commission has initiated a pilot project for NTA development in the Booth Bay Harbor area, in response to state legislation.[5] A state law passed in 2010 directed the Maine PUC to determine whether creating one or more smart grid coordinators is in the public interest, and if so, to adopt standards for smart grid coordinator(s). The Booth Bay Harbor project is being coordinated and managed by a company named GridSolar. The project will eventually include about 30MW of distributed solar PV, plus demand response, energy efficiency, and other resources.

- Maryland followed the state's Maryland Grid Resiliency Task Force *Report* (2012) with a Microgrids Task force in 2014 (Maryland Energy Administration, 2014). The Microgrids Task Force *Report* recommends pursuing microgrids for "critical community assets," and proposes a new "Grid Transformation Program… for public purpose microgrid projects, advanced controls, and energy storage." The *Report* concludes that Maryland electric distribution companies can own and operate DG and storage systems for sale into the PJM wholesale markets and for sale on a Maryland Public Service Commission approved fee-for-service to microgrid retail customers. Long term, the *Report* recommends a "broad public debate" about third-party owned and operated microgrids, which "are not feasible under current Maryland law."

- Massachusetts Department of Public Utilities is requiring all electric distribution companies to file grid modernization plans (MA-DPU, 2014). The plans have four major objectives: (1) Reducing the Effects of Outages; (2) Optimizing Demand, Including Reducing System and Customer Costs; (3) Integrating Distributed Resources; and (4) Improving Workforce and Asset Management. Massachusetts DPU also directs the utilities to ensure stakeholder input in their plan development.

- Michigan and Wisconsin parties are engaged in planning with the goal of avoiding the need to construct an estimated $500 million transmission line from Wisconsin to the western Upper Peninsula (Balaskovitz, 2015). Details of the plan are still developing, but a linchpin of the concept is a large combined heat and power generating plant (tentatively 280MW) proposed for installation and operation in Michigan's Upper Peninsula, to replace power from an existing coal-fired power plant (431 MW) slated for retirement in 2020.

- Minnesota (Burr, Zimmer, et al., 2013) commissioned a review of "barriers to and opportunities for microgrid development for energy assurance… ." The Minnesota *Report* (Burr, Zimmer, et al., 2013, Chapter V) includes a "Microgrid Roadmap" outlining state policy and regulatory actions to enable microgrid development. The *Report's* recommendations explicitly include: (a) support for NTA modeling as part of the Midcontinent Independent [Transmission] System Operator (MISO) planning

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[5] *An Act to Create a Smart Grid Policy in the State* ("*Smart Grid Policy Act*") (P.L. 2010 Ch. 539 codified at 35-A M.R.S.A. § 3143 (2010)). See also: www.gridsolar.com; Maine PUC Docket No. 2011-138; Maine PUC Docket No. 2013-00519; and Stanton, 2012.

process; (b) identifying "energy improvement districts" to support local microgrid development; (c) initiating a Minnesota Microgrid Pilot Program; and (d) providing rates and tariffs that support microgrids.

- New Jersey Board of Public Utilities (NJ-BPU, 2014) is supporting development of in-state generation and storage, especially for the support of critical facilities. The New Jersey Energy Resilience Bank, using federal Community Development Block Grant – Disaster Recovery funds, is providing support for developing distributed energy resources at critical facilities, so that they can remain operational during future outages. The first target facilities include water and wastewater treatment plants.

- New York Public Service Commission (NY-PSC, 2014a) has started an initiative called "reforming the energy vision (REV)," to address the future of both the state's regulated utility companies and regulatory practices. The REV initiative is comprised of two major components. Track One is "examining the role of distribution utilities in enabling market-based deployment of distributed energy resources to promote load management and greater system efficiency, including peak load reductions." Track Two will follow the first, "examin[ing] changes in current regulatory, tariff, and market designs and incentive structures to better align utility interests with achieving the Commission's policy objectives."

  In conjunction with the REV proceedings, New York's Consolidated Edison Company (ConEd) has received NY-PSC approval for a major Brooklyn/Queens Demand Management Program (NY-PSC, 2014b). This project will develop an NTA, combining energy efficiency and demand management along with customer- or third-party-owned and operated DG, plus an array of utility resources including storage, microgrids, and smart grid capabilities for Volt/VAR optimization and distribution management. Instead of a billion-dollar transmission system investment, ConEd will implement an estimated $200 million plan to develop approximately 17MW of traditional utility investments (e.g. in capacitor banks and load transfers, plus battery storage), plus about 52MW of "non-traditional utility-side and customer-side solutions" including combinations of energy efficiency…, storage, customer engagement, and demand response (NY-PSC, 2014b, pp. 3-7). The NY-PSC states (2014b, p. 2):

  > By this Order, the Commission is making a significant step forward toward a regulatory paradigm where utilities incorporate alternatives to traditional infrastructure investment when considering how to meet their planning and reliability needs. The program established herein provides an important opportunity to consider and observe the means by which the Commission's objectives for the REV proceeding may be achieved in the marketplace, through a demand-side management program using nontraditional utility and customer-side solutions to offset or eliminate the need for traditional utility infrastructure.

- Vermont utilities are engaged in some major transmission deferral projects, in response to the state law that mandates NTA analysis (see footnote 2, p. 8). Resources engaged in transmission deferral already include energy efficiency, demand response, net metering and DG. Some Vermont energy efficiency projects are represented in bids that have already cleared the ISO-New England forward capacity market. It is also noteworthy that the sluggish economy since 2008 has reduced electricity loads compared to the forecasts that were initially used to support proposed transmission upgrades (personal communications, Hans Prèsumè, Vermont Electric Transmission Company, 5 Feb 2014).

In addition to those activities specifically directed to NTAs or potential NTA components, many states have program requirements or incentives focused on some of the specific components that might make up NTAs, such as energy efficiency, demand-response, load-management, DG, and storage. Dozens of state policies are directed towards: financial and tax incentives for specific technologies; siting, zoning, and interconnections for renewable resources and distributed generation; using state and local government facilities as examples to demonstrate emerging energy management options, and more.[6]

Some state programs and activities that are indirectly related to NTAs include net metering provisions that allow for what is variously defined as meter aggregation, virtual, neighborhood, or community net metering, in 17 states, and renewable energy standards with specific goals or incentives for distributed generation, in eight states (IREC, 2014). Those provisions can at least theoretically support developing DG resources in specific grid locations where they will help to defer or replace other distribution or transmission investments.

For the time being, the obstacles to modeling, planning, and implementing NTAs under FERC jurisdiction are substantial. As this review shows, multiple observers are critical of the present situation because current financial incentives and cost allocation methods do not adequately support NTAs (e.g., Hempling, 2013; Warren, 2013; Watson and Colburn, 2014; Welton, 2014). This leaves NTAs dependent on state IRP and certificate of need procedures, to require the rigorous analysis necessary to determine when NTAs can prove to be cost-effective, better choices than the alternative transmission investments.

B. States can take specific steps to deploy NTAs when they are cost-effective

As Welton (2014, pp. 13-14) reports, IRP is presently required in 28 states and many other states can require NTA analysis in certificate of need proceedings. Here is a set of possible approaches that state utility commissions could take to ensure analysis of NTA options.

A preliminary step for state consideration is to review how rate designs and utility compensation incentivize the different resources that might comprise NTAs, such as energy efficiency, demand-response, load management, DG, and smart grid. The concern is that utilities

[6] See listings at Database of State Incentives for Renewables & Efficiency, www.dsireusa.org.

might not be fully dedicated to modeling, planning, and implementing a least-cost energy future, as long as utility financial incentives and shareholder earnings are not aligned with the required strategies. Possible solutions to this long-standing concern are part of the ongoing investigations in California, Hawaii, Massachusetts, and New York, and are related to the ongoing discussions around the country about future business models for public utility companies (see, for example, Fox-Penner, 2014).

A second step is to investigate the rules and regulations that might presently apply to differentiating utility rates and services by grid location. NTAs, by their focus on particular areas in the utility grid, raise the question whether specific services could be provided only to customers in a particular area, or if that would be considered "undue discrimination." There could already be some precedent for assigning specific grid related costs to specific customers; for example, some larger utility customers have been afforded the option of purchasing dual distribution feeders, to help avoid service interruptions. But, each state commission will need to review its own authorities and previous decisions to determine whether any changes are needed to facilitate differential service charges in support of NTA development.

A theoretically plausible alternative to geo-targeting would be to maximize the uptake of all cost-effective NTA resources throughout each utility's service territory. If comprehensive and continuous actions were underway to ensure developing all cost-effective energy efficiency, demand response, load management, distributed generation, and energy storage, then NTA resources would be implemented and their presence and growth would affect IRPs and certificate of need proceedings. Depending on the modeling techniques used to determine cost-effectiveness, this approach could even take into account the effects of such resources on avoided transmission and distribution system infrastructures. Stakeholders can ask themselves how close existing utility practices for integrated least-cost planning and action come to achieving this theoretically ideal status. A related question is whether utilities are eligible to own and operate various NTA resources. States could find that existing legislation restricts utility options in some ways.[7]

A third step is to review and understand how NTAs might complement, or conceivably conflict with, other state regulatory policies and practices. For example, many states have existing provisions supporting energy efficiency, renewable resources, distributed generation, and smart grid development. These are all NTA components that could also be included in compliance strategies for EPA Rule 111(d) and for achieving other environmental objectives. Vermont provides a compelling example, because several years of concerted state actions there have enabled deferral of substantial transmission investments (Farrell, 2014, pp. 34-38).

Hempling (2013, p. 20) recommends that state commissions build internal departments with expertise in NTAs, and then consider requiring utilities to hold open competitions for NTAs and create a path for cost recovery for those NTAs. As an early step, state commissions could

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[7] This question, about utility ownership of NTA resources (explicitly, of distributed generation) is investigated in Ken Costello's paper**,** *Utility Involvement in Distributed Generation: Regulatory Considerations* (NRRI Report No. 15-01**;** February 2015).

identify, or require utilities to identify, one or more specific transmission projects for consideration, and invite interested parties to propose NTAs. This process could build on the work that is already underway in New England (New England States Committee on Electricity, 2012) and most specifically in the states of Maine (for the Booth Bay Harbor pilot project) and Connecticut and Maryland (for developing public-purpose microgrids).

Khodaei (2014) proposes "provisional microgrids" as a tool for preventing transmission congestion. Khodaei defines a provisional microgrid as an area with "clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid." The difference that would make a microgrid "provisional" would be that intentional islanding would not need to be implemented. A provisional microgrid would have a functional "master controller" though, analogous to a flow-gate or limiter, capable of restricting maximum loads as necessary to meet transmission system requirements. Eventually, Khodaei expects that "microgrid clusters or super-microgrids" might be developed. This approach could build on existing utility capabilities and take advantage of smart grid implementation, by developing a full suite of options for managing loads on selected circuits. An early step could be to identify one or more substations or distribution feeders that are good candidates for provisional microgrid treatment, because there is ample time for planning and developing NTA components to defer or alleviate the need for transmission or distribution expenditures that would otherwise be required.

Another idea is proposed by Manfren et al. (2011), who recommend that urban communities, perhaps local governments, would be the primary agents for analyzing such infrastructure decisions. This is similar to the process underway in Connecticut, where municipalities are proposing public-purpose microgrids. A major benefit of including local governments or communities in the NTA analysis and planning process could be to engage community planners in working towards simultaneously optimizing multiple infrastructures, such as electricity, natural gas, water and wastewater, communications, and even transportation. Coordinating planning with local governments and communities would facilitate early demonstrations, to identify some of the ways that smart-city development (IEEE Smart Cities, 2014; Smart Cities Council, 2014) might be coordinated with smart-grid, with the possibility of avoiding multiple kinds of infrastructure costs.

In addition, states with restructured utilities could include provisions towards NTA development in the requirements for standard offer service. Gonzales (2014) has proposed a starting-point, which would be to require bidders for standard offer service to include in their proposals resource portfolios that meet state standards for renewable or clean energy and energy efficiency programs for customers. That could be a valuable starting point, but admittedly still leaves the question of whether or how to geo-target these kinds of resources to particular grid locations. Those states with community-aggregation for customer choice service could be good candidates for inviting a focus on specific grid locations. Policy makers could strengthen that opportunity by inviting those communities to participate in early smart-city development, possibly including special incentives for consumers who opt-in for implementing various NTA components.

III. Conclusion

FERC efforts through Orders 890 and 1000 to establish "comparable consideration" of NTAs could fall short because of the difficulties inherent in applying FERC jurisdiction over transmission rates as leverage for developing non-transmission resources. The absence of mechanisms for NTA cost-sharing appears to be a sufficient hurdle that will prevent the rapid adoption and implementation of all cost-effective NTA resources. Nevertheless, institutionalizing opportunities for NTA analysis could prove to be a most important first step towards developing NTAs, and states are likely to find they already have opportunities to advance cost-effective NTAs through existing IRP and certificate of need proceedings, often assisted by public policies that support one or more individual NTA components. With the possibility that NTAs could produce cost-savings for utility customers, it is worth some effort to enhance existing state procedures, or even develop new ones if necessary, to ensure opportunities for NTAs to compete.

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