A WIRES Report

on

MARKET RESOURCE ALTERNATIVES:

An Examination of New Technologies in the Electric Transmission Planning Process

London Economics International LLC

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www.WIRESgroup.com

WIRES

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WIRES PREFACE

The following report examines an important aspect of North America's evolving electric power infrastructure, which the Federal Energy Regulatory Commission ("FERC") refers to in its Order No. 1000[1] as "non-transmission alternatives." A more appropriate label is "market resource alternatives" or "MRAs," for reasons that should become apparent. WIRES[2] is pleased to release this report as another in a series of studies of the changing, modern interstate electric system. It is purposely designed to provide policy makers, the public, and industry participants themselves with an understandable but data-rich analysis and thoughtful observations about how developments like MRAs affect the need for, and planning of, high voltage electric transmission. WIRES commissioned this report on MRAs to provide:

- **An understanding of MRAs as both supply-side and demand-side solutions that include distributed generation ("DG"), energy efficiency ("EE"), demand response ("DR"), utility-scale generation, and storage. The study examines how the relative merits of transmission and MRAs should be evaluated in regional, interregional, or other transmission planning processes;**
- **A reference point or framework within which planners can evaluate MRAs relative to other resources in light of their demonstrated benefits and the demonstrable benefits of new or upgraded transmission infrastructure; and**

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1 Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, FERC Stats. & Regs. ¶ 31,323, 76 Fed. Reg. 49,842 (2011) [hereinafter Order No. 1000], *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g*, Order No. 1000-B. 141 FERC ¶ 61,044 (2012), *aff'd sub nom. South Carolina Pub. Serv. Auth. v. FERC*, --- F.3d ---, 2014 WL 3973116 (D.C. Cir. Aug. 15, 2014). FERC's characterization is at least partly attributable to its mission in Order No.1000 to improve regional and interregional transmission planning processes. LEI therefore examines MRAs on their individual, and quite considerable, merits and in the context of transmission planning. LEI concludes that planners need to judge transmission and MRAs using the same criteria to ascertain how the services and benefits of each resource complement and even supplement each other.

2 WIRES is an international non-profit association of investor-, member-, and publicly-owned entities dedicated to promoting investment in a strong, well-planned, and environmentally beneficial high voltage electric transmission grid in North America. WIRES members include integrated utilities, regional transmission organizations, independent transmission and renewable energy developers, Crown corporations, and engineering, environmental, and policy consultants. WIRES principles and other information are available on its website: www.wiresgroup.com Enquiries and comments are always welcome.

- **Appropriate lessons learned or "best practices" to ensure that investment in MRAs and/or transmission yield the optimal benefits for the money invested in each case.**

We believe that this MRA study, performed expertly by London Economics International (LEI), fills a gap in the public's understanding of the capabilities of the new technologies and resources that are helping make the electrical system more efficient, smarter, more resilient, and more flexible. In reviewing LEI's work, it becomes evident that both the evolving network of electric transmission facilities and the advent of distributed generation and other MRAs are new and dynamic forces within the power industry. Both are fulfilling new roles and providing new benefits to the electric economy. MRAs are reinventing how we think about the grid. A range of new "smart" options and resources are providing consumers with increased mastery of energy consumption, planners with unprecedented vision and analytical choices, and operators with a new and refined ability to control system operations. Similarly, today's transmission system is more highly networked and animated by digital technologies than could have been anticipated in the middle of the last century. It is, above all, the platform for the coming changes in how we produce and use electric energy. For that salient reason, strengthening the transmission system should be the primary objective of the planning process, as opposed to the last resort after all other alternatives are exhausted. MRAs and new transmission investments are complementary and overwhelmingly positive developments in the transition away from the weak markets, discrete systems, and electro-mechanical technologies of the last Century and toward a more resilient, flexible, and economically efficient means of producing and delivering electricity. In the final analysis, the goal of both MRA and transmission investments is cost-effective and reliable energy services. We therefore urge policy makers, planners, and investors to rely on LEI's explanation of MRAs when making decisions about transmission investment and operational changes across the grid.

This study follows on the heels of The Brattle Group's 2013 examination of transmission benefits[3] raised in virtually every "beneficiaries pay" cost allocation debate. Like that study, LEI's study addresses another important aspect of Order No. 1000 left virtually unexplored in FERC's broad requirement that transmission planners evaluate the value of deploying MRAs when planning, or evaluating the need for, transmission. Chapter 1 delves into the basic definitional and operational parameters of MRAs, including how MRA benefits compare generally to those provided by transmission. Chapter 2 brings the MRA analysis into the context of processes mandated under Order

[3] The Brattle Group, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments,* prepared for WIRES (July 2013), available at www.wiresgroup.com

No. 1000, as it applies regionally and inter-regionally, in both organized and bilateral markets. Chapter 3 provides key case studies to assess the impact of considering or deploying MRAs on the outcome of specific transmission planning processes. Chapter 4 provides critical observations based on these cases and LEI's research elsewhere. Adding technical depth, LEI also furnishes important appendices that should provide planners with methodological suggestions for a better process that results in extracting optimal benefits for both MRA investments and transmission investments.

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WIRES' commitment to promoting transmission investment is based on its belief that transmission enables consumer choices and supports markets, deployment of new technologies, and access to a range of available energy resources. It is a fundamental hedge against uncertainties surrounding the nature and timing of new technology development and shifting patterns of supply and demand. In other words, long-lived transmission facilities provide adaptability and optionality. In commissioning this work, WIRES' sought a balanced perspective on the relative merits of MRAs as they are evaluated in today's increasingly complicated transmission planning processes that have to account for more system components over larger and larger geographic areas. That balance has been achieved, in our view. Although MRAs can provide the not-insignificant benefits of being located closer to home, lending the grid resilience in the face of regional disturbances, , or empowering consumers to exert choice about how power is supplied or consumed, the LEI study nevertheless casts significant doubt on the storyline that the large-scale, integrated grid infrastructure is outmoded and can or should be replaced by extensive deployment of discrete technologies like installing rooftop solar units, building community power or microgrids, and growing efficiency gains. LEI's explanation of the relative limitations of MRAs goes to the heart of "off grid" mythologies about how MRAs signal the decline and obsolescence of the integrated grid. It states:

> **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 for transmission, and individual MRAs typically provide only a partial suite of the services that transmission provides. Nevertheless, MRAs (either individually or in combination) provide specific benefits and can serve as complements to transmission, and vice versa.[4]**

That said, the future is bright for MRAs and we expect these technologies to be widely deployed to make the electric power system more efficient, dynamic, and resilient. However, a close

[4] LEI, Introduction at 22.

look at the operational and technical capabilities and value of MRAs in specific instances, especially when compared to other infrastructure investments like transmission, supports the conclusion that MRAs and transmission usually perform different but complementary tasks over time. For example, LEI states that:

> **. . . MRAs can be broadly considered as programs or technologies that complement the transmission system and provide benefits similar to those provided by the transmission system. But some MRAs may face limitations that prevent them from providing the full suite of services and benefits that are created as a result of transmission investment. . . .The challenge for the regulators and planners is striking the right balance, not simply picking the "best" technology.**[5]

Transmission planning is not a "zero sum game." Armed with an understanding of the respective benefits of these technologies, planners and regulators should not feel they must decide in the alternative between supporting investments in electric transmission or investments in DG or other MRAs. The following analysis makes clear that the complexities of system planning and the need to optimize the benefits from any investment in technology is seldom a choice between winners and losers. If planning is to produce the best results, it simply cannot begin with a presumption that the sizeable future investment in electric transmission that economists and operators forecast as a necessity is somehow becoming optional.

In sum, it is important for the industry to move beyond the idea that MRAs are a threat to transmission investment. In fact, MRAs may necessitate *additional* transmission investment in many instances. But, at bottom, LEI identifies – benefit by benefit – the extent to which an MRA can or cannot provide the same services as transmission. The study thereby reveals the complementary nature of the relationship between these types of facilities and the probability that planners who fail to consider the full effect of MRAs or the full range of transmission benefits will be settling for sub-optimal investment in the systems under consideration, with untold economic and reliability consequences.

Perhaps most important, this study provides relevant information for practical use by individual utility, regional, and inter-regional planners who are charged with assessing the need for new levels of capacity, flexibility, operability, efficiency, or reliability from our electric power system. In that regard, the multiple lessons learned from LEI's analysis come down to the need to perform full cost-benefit analyses of the best ways to satisfy the technical needs of the electrical system, judging

[5] LEI, at 27

MRA solutions and proposed transmission projects using the same criteria. In that regard, LEI's conclusions resemble those which anchored the study performed for WIRES in 2013 by The Brattle Group. That is to say, the key to achieving optimal economic, reliability, and public policy outcomes is to provide a comprehensive analysis of the <u>full range of benefits</u> that can be derived from a proposed transmission project as well as the available alternatives. One caveat, however -- WIRES' support for comprehensive analyses of transmission and MRA benefits should not be understood as support for more prolonged planning or permitting processes. Transmission development is difficult enough as it is.

Transmission planning to date has seldom met this exacting test and this is troubling. There is general agreement on the importance of accelerating additions to the high voltage grid in light of the age of grid facilities, the shift in the industry's fuel mix including the growth of renewable resources, the growing possibility of 'decarbonization' regulations, bigger bulk power markets, and the prospect of a surge in the use of electric vehicles. While we are grateful that the need for major investment in the transmission grid is widely acknowledged, that alone won't do the job. Informed observers likewise recognize that "less successful outcomes are entirely possible. Transmission expansion could falter for any of the customary reasons, not to mention some new or unforeseen problems. Another decade or two in which new transmission lags behind the need for new capacity will have dramatic consequences for the range of supply choices we can access."[6] In hopes of diminishing the "customary" challenges and avoiding the new and unforeseen problems that could defer or deter transmission investment, WIRES offers the information and analysis that follows in support of more aggressive plans to strengthen the North American grid and thereby help ensure cost-effective and reliable energy services to all industrial, commercial, and residential consumers of electricity.

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[6] Peter Fox-Penner, *Smart Power: Climate Change, the Smart Grid, and the Future of Electric Utilities*," (2010), at 93.

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WIRES gratefully acknowledges the integrity and hard work of the economists at London Economics International, most notably Julia Frayer and her colleagues Sheila Keane and Eva Wang. Their understanding of the industry and their analytical skills has served to make this a high quality work product and it is therefore our hope that the industry will take heed of its important data and insights. Comments and further insights into this important subject matter are always welcome at www.wiresgroup.com.

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MARKET RESOURCE ALTERNATIVES:
AN EXAMINATION OF NEW TECHNOLOGIES IN THE ELECTRIC TRANSMISSION PLANNING PROCESS

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SYNOPSIS

WIRES commissioned London Economics International LLC ("LEI") to provide a report on market resource alternatives ("MRAs"). The purpose of this Report is to provide external parties with a clear understanding of MRAs, and compare their features - advantages and shortcomings - relative to transmission. In addition, based on analysis of how MRAs have been examined by planners and regulators, LEI also proposes a set of analytical tools and techniques that can be used to effectively evaluate MRAs alongside transmission investment. The Report consists of four chapters: the first chapter addresses the question "what are MRAs and why do we need to analyze them?"; the second chapter discusses how MRAs are considered in federal and regional policy; the third chapter shows how MRAs are used in organized markets in the U.S. through a case study analysis; and the fourth chapter provides a proposed "toolkit" of analytical tools and techniques that would allow for the effective evaluation of MRAs within the transmission planning environment.

ABOUT THE AUTHORS

Julia Frayer is a Managing Director at London Economics International, with more than 15 years of experience providing economic analysis to a diverse set of clients in the power sector and associated infrastructure industries. In the area of transmission, Julia has provided advisory on a variety of subject matters, ranging from economic valuation to cost-benefit analysis, macroeconomic impact studies to revenue forecasting and transmission tariff design. Julia has worked with utilities, independent investors, financial institutions, regulators, RTOs/ISOs and policymakers. Over the past decade, she has led numerous projects involving the blending of practical commercial business sense, economics, and state of the art application of analytical techniques, including econometrics, game theory, options analysis, and simulation modeling. She has made a promise to continue to work in the sector so long as she can learn something new every day.

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DISCLAIMER

The opinions expressed in this report as well as any errors or omissions, are solely those of the authors and do not represent the opinions of other clients of London Economics International LLC.

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Acronyms

AC	Alternating Current
BPA	Bonneville Power Administration
BPA-TS	BPA Transmission Services
BUG	Back Up Generation
CAISO	California Independent System Operator
CARIS	Congestion Assessment and Resource Integration Study
CBA	Cost-Benefit Analysis
CMP	Central Maine Power
CPCN	Certificate of Public Convenience and Necessity
CPUC	California Public Utilities Commission
CREZ	Competitive Renewable Energy Zone
CRPP	Comprehensive Reliability Planning Process
CRP	Comprehensive Reliability Plan
CSPP	Comprehensive System Planning Process
DC	Direct Current
DG	Distributed Generation
DOE	Department of Energy
DR	Demand Response
EE	Energy Efficiency
EERS	Energy Efficiency Resource Standards
ERCOT	Electric Reliability Council of Texas
FCA	Forward Capacity Auction
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GSRP	Greater Springfield Reliability Project
GW	Gigawatt
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
IRP	Integrated Resource Plan
ITP	Integrated Transmission Planning
LEI	London Economics International LLC
LMP	Locational Marginal Price
LRA	Local Regulatory Authorities
LTPP	Local Transmission Planning Process
MAPP	Mid-Atlantic Power Pathway
MISO	Midcontinent Independent System Operator
MOPC	Markets and Operations Policy Committee
MPRP	Maine Power Reliability Project
MPUC	Maine Public Utility Commission
MRA	Market Resource Alternative
MTEP	MISO Transmission Expansion Planning
MVP	Multi Value Project
MW	Megawatt

NEEWS	New England East-West Solutions
NERC	North American Electric Reliability Council
NETO	New England Transmission Owner
NPV	Net Present Value
NTA	Non-Transmission Alternative
NTC	Notification to Construct
NTTG	Northern Tier Transmission Group
NYCA	New York Control Area
NYSIO	New York Independent System Operator
OATT	Open Access Transmission Tariff
O&M	Operations & Maintenance
PAC	Planning Advisory Committee
PATH	Potomac-Appalachian Transmission Highline
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PV	Photovoltaic
RIRP	Rhode Island Reliability Project
RNA	Reliability Needs Assessment
RPG	Regional Planning Group
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
SBSA	Statistical-based Scenario Analysis
SCE	Southern California Edison
SDGE	San Diego Gas and Electric Company
SERTP	Southeastern Regional Transmission Planning
SPM	Sub-regional Planning Meetings
SPP	Southwest Power Pool
SRMC	Short-run Marginal Cost
STEP	SPP Transmission Expansion Plan
TEAM	Transmission Economic Assessment Methodology
TO	Transmission Owner
TPBPM	Transmission Planning Business Practices Manual
TPP	Transmission Planning Process
TRR	Transmission Revenue Requirement
TRTP	Tehachapi Renewable Transmission Project
TSP	Transmission Service Provider
TWG	Transmission Working Group
WECC	Western Electricity Coordinating Council

Executive Summary

WIRES commissioned London Economics International LLC ("LEI") to provide a Report on market resource alternatives ("MRAs"). Specifically, WIRES asked LEI to determine whether and when MRAs can augment and/or replace transmission, and how MRAs and transmission can be evaluated on equal footing in the system planning context. The purpose of this Report is twofold. First, we seek to provide readers with a clear understanding of MRAs and their features - advantages and shortcomings - relative to transmission. Second, drawing on analysis of how MRAs have been examined by planners and regulators to date, we propose a set of analytical tools and modeling techniques (which we refer to as the "toolkit") that can be used to effectively evaluate MRAs alongside transmission investment.

An understanding of MRAs and how they can be compared to and evaluated alongside transmission investment is critical given the increasing attention being paid to MRAs and as a result of advancements in technology, policy evolution, and the basic need for transmission investment to maintain, modernize, and expand the grid. System planners are required to consider reliability, market outcomes, and transmission congestion as well as public policy as they work to develop a robust power grid. 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.

Observations

Through our research and case studies, LEI developed key observations about MRAs and transmission investment.

- ***Transmission provides a variety of services and offers a broad range of potential benefits.*** Understanding the types of services and benefits transmission can provide is necessary as MRAs will be evaluated in terms of the services and benefits they can provide when compared to transmission.

- ***An MRA generally is able to provide only a partial suite of services that transmission provides.*** MRAs may provide some of the services that transmission can provide, but they cannot perfectly replace transmission. Furthermore, the services each MRA can provide vary.

- ***Comprehensively measuring the benefits and costs to customers is necessary in order to distinguish among the feasible solutions and the various services that MRAs and transmission can provide; relying on least cost analysis is not sufficient.*** In the analysis of MRA policies regionally, federal guidelines, and specific case studies involving MRAs, we have found that such a comprehensive analysis is rarely performed.

- ***It is important to consider both the magnitude and breadth of benefits of MRAs compared to transmission.*** One must consider the ability of a solution - be that MRAs or transmission - to provide benefits and services to various customer classes and over what geographic and time dimension. Different MRAs provide benefits of varying magnitude and breadth. Transmission, on the other hand, is typically built to provide benefits to the larger regional system over a long period of time.

- ***Operational uncertainty is an important consideration for MRAs.*** We have found that there are often high levels of operational uncertainty associated with MRAs, especially in the longer term. Given the technical and operational characteristics of transmission system planners historically have not had to give significant weight to operational uncertainty in their analyses.

- ***A comprehensive analysis must include consideration of negative and positive externalities associated with potential costs and benefits.*** Externalities can be positive; there are examples of strong complementarity between transmission and some MRAs, where transmission opens up further opportunities for MRAs, and vice versa. Externalities can be negative; some MRA installations require additional investment to maintain system reliability.

Recommended Tools and Techniques

We recognize that system planners have their own analytical approaches and planning processes that have been developed over the decades to provide an extremely reliable and affordable electric system. We are not attempting to specify an approach. We recognize that transmission planners and ISOs/RTOs may have specific processes in place that are unique to their situation. Rather than a "one-size fits all" analytical approach, we are recommending a "toolkit" for system planners with various suggested modeling tools and analytical techniques that can be deployed to analyze transmission and MRAs.

The analysis deployed by system planners should be inclusive, and consider all feasible solutions – transmission and MRAs. The analysis should be sufficiently detailed and comprehensive so as to distinguish between the feasible solutions' traits and defining characteristics and benefits. We suggest several guidelines that will provide for an effective analysis of MRAs and transmission:

- MRAs should be judged on the same criteria for reliability and economic benefits as proposed transmission;

- Technical feasibility should be a requirement for any solution, not an option; the ability of MRAs to consistently meet the technical (reliability) needs of the system are sometimes overlooked for the sake of policy;

- MRAs and transmission are not equals in the services and benefits they provide, therefore, the evaluation framework must be able to assess a broad set of benefits and costs to fairly compare MRAs and transmission;

- A robust cost-benefit analysis should measure and quantify the uncertainties and risks associated with MRAs and transmission;

- Economic cost-benefit analysis should consider the dynamic evolution of the system; such an analysis may show potential for complementarity between transmission and certain MRAs, which could justify the need for more investment.

A successful analytical framework, consistent with these guidelines, should

1. Identify all the benefits and costs and gather them under the umbrella of a cost-benefit analysis,

2. Use the right set of tools to measure both those benefits and costs and the risks and uncertainties involved, and

3. Conduct analyses that specifically address the identified challenges for evaluating both MRAs and transmission in an efficient manner.

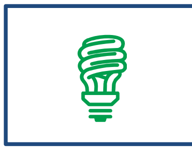
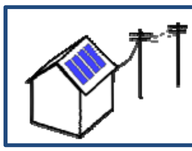
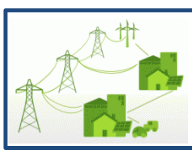
If one evaluates MRAs and transmission technically to the same specified "needs" criteria, across the same categories of benefits and over the appropriate geographical and time dimensions, the most robust and efficient investments can be chosen.

Understanding MRAs

MRAs can be broadly defined as a group of solutions to identified electric system needs that do not involve traditional transmission infrastructure. MRAs are often referred to as non-transmission alternatives ("NTAs"), a misleading convention that incorrectly implies that MRAs are always a substitute for transmission. MRAs can in fact be complements to transmission infrastructure and should be thought of as one element in a portfolio of infrastructure elements that together are necessary for the efficient and reliable provision of electricity to customers. Indeed, the electric system would not be able to operate and provide services to customers if there were only investment in either transmission or MRAs in isolation.

MRAs come in a variety of forms and can include supply-side resources (for example, conventional generation and distributed generation or advanced generation-like technologies such as batteries and storage) and demand-side resources (such as demand response and conservation/energy efficiency programs), or a combination of resources that are not conventionally associated with transmission. Discussions of MRAs occurring in wholesale power markets and at state regulatory commissions generally focus on six categories of MRAs: energy efficiency; demand response; utility-scale generation; distributed generation; energy storage; and smart grid technology (as summarized in Figure 1 below).

Figure 1. MRA Categories

	**Energy Efficiency**	improvements that result in the ability to use less energy to provide end-use customers with the same (or a better) level of service in an economically efficient way
	**Demand Response**	changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time or to incentive payments
	**Utility-scale Generation**	relatively large generators that connect to the grid at the transmission (high voltage) level
	**Distributed Generation**	small generation systems located at a customer site
	**Energy Storage**	technologies that allow electricity generated at one time to be used at another time
	**Smart Grid**	technologies that enable a more efficient use of the electric power grid through computer-based remote control and automation

Services provided by transmission and MRAs

In order to put the capabilities and benefits of each MRA in context, it is first important to understand the types of services that transmission provides. Transmission provides for the transportation of electric power from producers (generators) to customers (load), often times over long distances. Transmission can also help to ensure resource adequacy because it allows generators located in an isolated area to serve customers in another area of the power grid (in this way, transmission effectively provides capacity). In addition to facilitating the delivery of energy and capacity, transmission can provide other benefits. For example, transmission system reinforcements can reduce system losses and improve overall system efficiency. Transmission can also provide support to the electric power grid through the provision of certain ancillary services, which are used to keep the grid operating smoothly. Transmission can provide insurance against uncertain future market events and the costs of such unforeseen events on customers. For example, if in the future a generator were to unexpectedly go off line, transmission lines could allow other generators on the system to serve customers. Transmission can also reduce production costs of energy through expansion of a market (and increased competition from other existing resources) as well as provision of market access to new resources. As a consequence of expanding access to market for existing and new resources, transmission can also help to reduce the emissions footprint of the market as a whole and curb harmful pollutants such as carbon dioxide and other greenhouse gases.

It is important to consider to what extent MRAs can produce these same services, over what time dimension they can be counted on to provide these services, and for what geographical area. In many cases, MRAs may have shorter economic lives (or less certain longevity in terms of the market benefits that they create) than transmission, and provide benefits to a smaller or more localized geographical segment of customers.

In Figure 2 below, we have prepared a visual comparison of the services that various current MRA technologies can provide relative to transmission. This comparison is meant to reflect the relative abilities of generic MRAs and generic transmission investment to provide broad classes of services. In reality, the specific services will vary with the characteristics of the individual project (i.e., proposed solution) and the underlying "need." Furthermore, the comparative charts of transmission and MRAs in the following sections reflect the overall experience of LEI and WIRES members with the technologies as they exist today. We recognize that technology (both MRAs and transmission) is evolving rapidly and that MRAs and transmission will likely be able provide a more extensive list of services in the future. Finally, we recognize that this type of comparative chart can simplify the relationship between transmission and MRAs. As mentioned earlier, transmission and MRAs are interconnected – a system comprised of one or the other would not be functional. In this sense, transmission can only provide energy and capacity if there is a generator connected to the grid able to generate the energy and capacity. Likewise, generation can only provide energy and other services if there is a transmission system that connects the generator to customers. Nevertheless, the comparison of relative abilities under current technology provides a high level consideration of relative strengths and weaknesses of different MRAs, from which benefits can be evaluated. Such a comparison of services is also a useful cross-check for the toolkit, which needs to contain tools and techniques that can capture such differences in services provided, technical characteristics, and ultimately economic costs and benefits.

We observe that individual MRAs are generally not capable of providing all of the same services that transmission provides for the same tenure and geographical dimension. Furthermore, there is considerable variety among MRAs in their ability to provide services. With the exception of utility-scale generation in limited circumstances, no single MRA is a workable substitute for transmission. However, in certain instances, depending on the identified needs of the system, other MRAs (either individually or in combination) can be beneficial and can serve as complements to transmission, and vice versa.

Figure 2. Services provided by MRAs relative to transmission

		Transmission	Energy Efficiency	Demand Response	Utility-scale Generation	Distributed Generation	Energy Storage	Smart Grid - Distribution
What	Energy	●	◑	◑	●	◕	●	●
	Capacity	●	◑	◑	●	◑	◕	○
	Ancillary Services	●	○	◑	●	◕	●	◑
	Reduce system losses	●	◑	◑	○	◔	◔	◔
When	Long lifespan	●	◕	○	◕	●	●	●
	Continuous basis	●	◕	○	◑	○	●	●
Where	Regional	●	◑	◑	●	◔	◔	○
	Local	●	●	●	●	●	●	●
	Micro	●	●	●	○	●	●	●
How	System/Wholesale	●	○	○	●	○	●	○
	Customer/Retail	○	●	●	○	●	○	●
	TOTAL	●	◑	◔	◕	◑	◕	◑

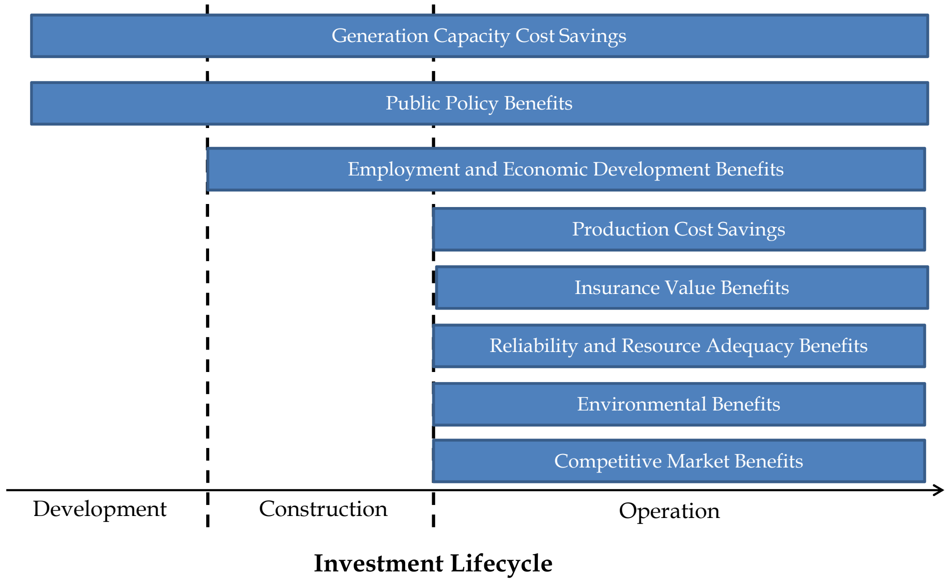
● Provided ○ Not provided

Given the characteristics of transmission, it tends to provide a broad array of benefits that accrue to a wide variety of parties over a large geographical dimension. That is, the benefits accrue at a micro or local level (for example, to the investor or a particular community), but transmission also directly benefits a broader set of customers in the electricity sector and indirectly creates benefits for society as a whole, for example through achievement of public policy and macroeconomic benefits (see Figure 11).

When considering if and how MRAs are able to provide the equivalent benefits of transmission, it is important to understand any challenges or limitations to the ability of MRAs to deliver these benefits (or for system planners and operators to take advantage of these benefits). Not only is it important to understand which of these benefits MRAs can provide, but also to consider the magnitude and breadth of the benefits.

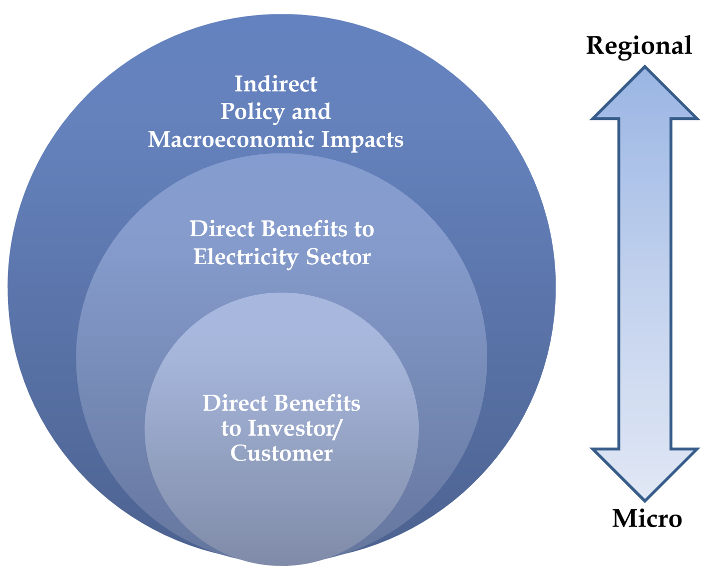
Transmission delivers its services and provides benefits throughout its long lifecycle. And once built, a transmission asset is a fixed element of the power system and therefore its existence is not dependent on market dynamics. In contrast, some MRAs such as generation (either utility-scale or distributed) or demand response may decide to exit the market and close operations if market conditions are not attractive. The permanent nature of transmission - once in service - means that system planners have ***reasonable certainty*** that transmission would provide services and benefits would accrue over the transmission asset's life. Experience has shown that there is a higher degree of uncertainty associated with MRAs, both in terms of the services and the benefits they can provide.

Figure 3. Potential Benefits of Transmission Investments Identified by WIRES



Note: the ordering of the benefits in the chart above does not reflect the relative magnitude of benefits

Figure 4. Magnitude and Breadth of Benefits



Optionality

The value of additional potential gains or losses that may be realized once the initial investment has been made.

Finally, when considering the benefits of transmission or MRAs, it is important to consider the optionality associated with the investment. These can be either positive or negative: for example, if a solution can provide an option to delay other investments or an option for future expansion, that would have a positive value to customers and system planners alike. On the other hand, if a solution requires additional incremental investment to come online (perhaps in the form of additional infrastructure), that cost should also be considered.

Practical Experience with MRAs

Practical experience with MRAs is relatively limited. FERC's Order 1000, issued in 2011, requires consideration of MRAs in the regional transmission planning process. However, it does not establish any requirements as to which MRAs should be considered or what the appropriate metrics for evaluating MRAs against transmission solutions would be. We found that MRAs appear to generally be considered in the transmission planning process in Independent System Operators and Regional Transmission Organizations ("ISO/RTOs") although the timing of an analysis varies on a RTO-to-RTO basis. Generally, evaluation of MRAs completed to date appears to be targeted and localized, rather than comprehensive. This is not surprising as economic analysis of transmission is also a relatively nascent but evolving component of the system planning process.

We selected four case studies that cover a variety of MRA technologies and investment needs, apply varying levels of analytical techniques for consideration of MRAs and transmission solutions, and highlight different aspects of the interplay between MRAs and transmission investment. Specifically, we considered the following case studies in our review of MRAs: Boothbay Smart Grid Reliability Pilot project in Maine, I-5 Corridor Reinforcement Transmission Project by Bonneville Power Administration ("BPA"), PATH and MAPP transmission projects in PJM, and Tehachapi Renewable Transmission Project in California.

Figure 5. Summary of the case studies

	Boothbay Pilot	I-5 Corridor Reinforcement	PATH/MAPP	Tehachapi
Type of MRA Considered	✓ Back-up generation ✓ Demand response ✓ Distributed generation ✓ Energy efficiency ✓ Energy storage	✓ Demand response ✓ Distributed generation ✓ Energy efficiency ✓ Re-dispatch of existing generators	✓ Conventional generation ✓ Demand response ✓ Energy efficiency (implicit consideration in load forecast)	✓ Conventional generation (implicit)
Need	Public Policy, Reliability	Reliability	Reliability	Public Policy
Benefits considered/ analysis performed	Cost was primary criteria; reliability, diversity, and emissions reductions considered qualitatively	Total resource cost; participant cost; societal cost	Economic analysis not performed (focus on reliability)	Economic analysis not performed (focus on policy need)
Observations	▪ MRA resources may be available at reasonable cost to meet very specific and very local needs ▪ Deploying MRAs to address certain reliability needs may result in other reliability challenges ▪ Some MRAs are still not cost competitive ▪ Comprehensive, full scale cost-benefit analysis was not employed	▪ Without explicit consideration of uncertainty and timing issues, comparison of MRAs and transmission can yield misleading results ▪ There may be complementary relationship between transmission and MRAs, but it was not quantified in the analysis	▪ Ultimately, these projects were cancelled due to the demand reductions resulting from the recession, additional conventional generation and some demand response ▪ A more comprehensive analysis of load growth and capacity market uncertainty may have more fully reflected the insurance value of transmission ▪ An economic analysis of the full range of benefits provided by a project should be considered when evaluating transmission projects	▪ Transmission investment can serve as a complement to, and in fact a catalyst for, new generation ▪ Transmission can provide broader policy and macroeconomic benefits ▪ CAISO did not quantify those benefits or quantitatively evaluate the complementarity between transmission and new generation

The case studies provided examples of how MRAs have been evaluated by system planners in recent years. Although there were a number of different MRA technologies considered, and the "need" driver behind the projects varied (for example, reliability, public policy, etc.) there are several observations from these case studies that we used inform the development of a toolkit for effectively evaluating MRAs alongside transmission.

1) **A feasible MRA should be judged on the same criteria for reliability, economic, and public policy benefits as proposed transmission.**

2) **The ability of MRAs to consistently meet the technical (reliability) needs of the system are sometimes overlooked for the sake of policy** – technical feasibility should be a requirement, not an option, of a thorough evaluation.

3) **The evaluation framework must be able to assess a broad set of benefits and costs to fairly compare feasible investment options.** The analysis needs to capture the differences in the characteristics of transmission and MRAs.

4) **A robust cost-benefit analysis should measure and quantify the uncertainties and risks associated with MRAs and transmission.** Various modeling techniques exist that help quantify risks associated with different investments and resolve both exogenous and endogenous uncertainties.

5) **MRAs and transmission are not equal in the services and benefits each can provide** – a more comprehensive analysis of the various services and resulting benefits of each option should be undertaken to select the options that maximize benefits to customers.

6) **Economic cost-benefit analysis should consider the dynamic evolution of the system.** Such an analysis would show, on an objective and non-discriminatory basis, the potential impacts of new investment on the system and customers. In addition, such an analysis may identify complementary relationships between transmission and certain MRAs, which could justify the need for more investment.

Proposed Toolkit for Evaluating MRAs alongside Transmission

We recognize that system planners may have their own analytical approaches and planning processes in place and therefore we have not specified a "one-size fits all" analytical approach, but rather focused on the major components that we believe would yield an effective consideration of MRAs within the transmission planning process (i.e., the toolkit for system planners). As discussed in Chapter 4, the major elements of the toolkit are:

- use of a flexible framework, such as cost-benefit analysis, which allows for an analysis of various MRAs and transmission solutions on a comparable basis, even if the characteristics and services provided vary. This involves identification of benefits and costs, and setting out how one measures those and from whose perspective;
- selection of modeling and analytical tools that can evaluate and measure the expected benefits and costs on a realistic basis; and
- use of analytical techniques that deal with challenging aspects of economic cost-benefit analysis, such as uncertainty.

We are recommending building blocks that a system planner can employ as part of their current practices. In fact, the benefits that we are recommending to be measured are already considered in many instances by system planners, and many tools – such as simulation models - are also part of the standard set of analytical tools that are already routinely used by ISOs/RTOs. Even some of the analytical techniques are already in use at some RTOs (such as techniques that account for uncertainty).

This toolkit can be deployed in such a way to streamline the overall process, and winnow down the pool of projects that require a full cost-benefit analysis (see Appendix A). To the extent that system planners are able to clearly define what analyses they will conduct and in which order, that will help reduce the time needed for analysis in addition to ensuring that the investments chosen meet all the needs/criteria to provide a robust, reliable and affordable electric system.

Introduction

Market Resource Alternatives ("MRAs") can be broadly defined as programs or technologies that complement and improve the reliability of the existing transmission system. MRAs are often referred to as non-transmission alternatives ("NTAs"), a misleading convention that incorrectly implies that MRAs are always a substitute for transmission. MRAs can be thought of as one element in a portfolio of infrastructure elements that together are necessary for the efficient and reliable provision of power to customers. Indeed, the electric system would not be able to operate and provide services to customers if there was only investment in transmission or MRAs in isolation.

The first purpose of this Report is to provide readers with a clear understanding of MRAs, including the characteristics of MRAs, and a review of the services and benefit they can and cannot provide as compared to transmission. The second purpose of this Report is to gather lessons learned from actual system planning cases involving MRAs and to recommend a set of analytical tools and techniques (or a "toolkit") for effectively analyzing and comprehensively evaluating MRAs alongside transmission investment. An understanding of the benefits and challenges associated with the development and operation of MRAs is a critical component of properly evaluating MRAs in the transmission planning process. Armed with a comprehensive understanding of the comparative characteristics of MRAs and transmission, system planners will be able to evaluate MRAs alongside transmission projects and select the solution that best addresses the needs of the system and customers in an effective manner.

Before discussing MRAs in detail, it is important to provide some context by considering the system planning process. Historically, prior to deregulation and market restructuring, resource planning was completed on an integrated basis. Utility planners were tasked with considering and balancing transmission and generation investment[1] to ensure reliable, cost-effective service in the long-term. Utility planners could optimize the long-term system plans because they had control over both transmission and generation investment. With the evolution of deregulated wholesale power markets, which rely on private investment decision-making, and technological innovation that makes new technologies commercially available, system planners must now plan transmission investment with relatively limited certainty on the magnitude and location of future generation and/or demand-side resources in the long-term.[2]

[1] In addition, demand-side solutions were also actively considered in the planning process, and have been part of the resource planning mix since the 1970s. *See:* MIT. *Study on the Future of the Electric Grid.* 2011.

[2] In areas of the U.S. where utilities remain vertically integrated and where state utilities commissions have not implemented retail access and provide the primary direction and control of their state's demand-side programs, this future uncertainty is reduced.

What are the goals of system planning?

The primary role of system planning has been - and continues to be - to ensure reliable electric supply (i.e., "keeping the lights on"). Ensuring reliable supply is itself a challenging task – electric supply and demand must be balanced in real-time since currently there is not a practical, cost-effective way to store electricity on a commercial scale.

With the advent of competitive markets and the Federal Energy Regulatory Commission's ("FERC") Order 890 (issued in 2007) and Order 1000 (issued in 2011) system planners are required to analyze transmission congestion and to consider public policy in their transmission planning. As a result, transmission planners must work to develop a robust electric power system that addresses economic, environmental, and reliability challenges in an efficient manner.[3]

Reliability is generally evaluated by analyzing the transmission system under stressed conditions, in accordance with standards established by the North American Electric Reliability Council ("NERC").[4] NERC's reliability standards are meant to ensure reliable service in the face of uncertainty by modeling transmission system performance across a variety of future conditions and contingencies (see Text Box below). Once a reliability shortfall is identified, it creates a need for a transmission solution.[5]

<u>Basics Concepts in NERC Reliability Standards</u>

NERC reliability standards are designed to ensure that the reliable provision of electricity to customers continues despite uncertainty about future system conditions and contingencies. A ***contingency*** is the failure of an element on the system (i.e., a transformer, or a generator)

<u>N-1 criteria:</u> the system must be able to reliably serve customers in the event of a contingency on the system

<u>N-1-1 criteria:</u> the system must be able to reliably serve customers even when two contingencies occur consecutively on the system allowing for remediation between events

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[3] As we will discuss in more detail, the Federal Energy Regulatory Commission's ("FERC") Order 890 in 2007 and Order 1000 in 2011 was a catalyst for considered broader economic and policy goals in system planning.

[4] NERC is the FERC-supervised electricity reliability organization responsible for establishing and enforcing reliability standards for the U.S. bulk power system. Typically, system planners evaluate the transmission system under what is known as the N-1-1 contingency protocol. That is, the system must be able to reliably serve customers even when two contingencies occur on the system. An N-1-1 contingency protocol refers to Category C.3 of NERC's Reliability Standards for Transmission Planning. Specifically, the N-1-1 scenario is defined as a first contingency (i.e., loss of a transmission or generation element) followed by system adjustments, which are then followed by a second contingency. *See:* NERC. *Standard TPL-003-0b – System Performance Following Loss of Two or More BES Elements.* <http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=TPL-003-0b&title=System%20Performance%20Following%20Loss%20of%20Two%20or%20More%20Bulk%20Electric%20System%20Elements%20(Category%20C)&jurisdiction=United%20States>

As a result of NERC oversight, there is a great deal of similarity in the reliability evaluations used by system planners throughout the U.S.

Although NERC standards focus on reliability and not on the other benefits that are provided by transmission, given FERC Orders 890 and 1000 (discussed in detail below), system planners also are increasingly assessing a broad range of benefits alongside the cost projections, including: production cost savings, customer payment reductions, emission reductions, increased competition, increased market liquidity, macroeconomic benefits, and public policy benefits. In other words, the "need" for transmission is no longer simply a function of technical reliability, but rather is characterized by market-oriented and policy-oriented benefits. In summary, transmission lines, regardless of why they are built, usually provide a broad range of benefits. These benefits are important to consider even when a transmission investment is triggered on the basis of a technical reliability need. As such, it is important to consider how MRAs can achieve those same benefits when evaluating MRAs as potential solutions to the identified need.

How has system planning evolved in recent years?

Policies have evolved as wholesale electricity markets have matured, and the varied benefits of transmission have been recognized by system planners and policymakers. Since 2007, FERC has also mandated transmission providers to consider both reliability projects and economic transmission projects – investments that could improve market efficiency or reduce the overall costs of serving load – during the transmission planning process.[6] FERC found that economic transmission projects could reduce congestion costs, integrate efficient new resources (such as demand response), and accommodate new or increasing load.[7] This requirement has also spurred the consideration of alternatives to transmission solutions. In 2011, FERC mandated transmission planners to consider public policy projects in addition to reliability and economic projects.[8] Such an expansion of the scope of transmission planning has also served as an impetus for consideration of various solutions to the identified needs.

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[5] More recently, the concept of market efficiency has arisen in transmission planning, where a need for transmission can be identified on the basis of market inefficiencies or for economic reasons (such as congestion reduction). This report will cover both instances of need for investment - reliability and market efficiency. However, for simplicity, we start with a description the planning in the context of reliability drivers.

[6] In 2007, FERC issued Order 890, requiring transmission providers to include economic planning studies in the transmission planning process, and required an "open, transparent, and coordinated transmission planning process" at the regional level to address undue discrimination. Order 890 is discussed in more detail in Chapter 2.

[7] FERC Order 890. Issued February 16, 2007. P 310. <http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf>

[8] In 2011, FERC issued Order 1000, requiring transmission providers to consider "transmission needs driven by public policy requirements in the local and regional transmission planning processes." Order 1000 is

To date, system planners at Independent System Operators and Regional Transmission Organizations ("ISOs/RTOs")[9] have all integrated some form of economic analysis into their planning process. Several ISOs/RTOs rely on traditional production cost evaluations to determine if the production cost savings or customer (market price) savings of a proposed project outweigh the costs (for example, Electric Reliability Council of Texas, "ERCOT", the Independent System Operator of New England, "ISO-NE", the New York Independent System Operator, "NYISO", and the Pennsylvania-New Jersey-Maryland Interconnection, "PJM", all use the production cost approach and/or customer savings). Other ISOs/RTOs, such as the California Independent System Operator ("CAISO"), the Midcontinent Independent System Operator ("MISO"), and the Southwest Power Pool ("SPP"), consider a broader range of benefits that transmission can provide in their economic evaluation. Some of these other measured benefits include increased market competition, system reliability, access to renewable generation, and improved system losses.[10]

As grid integration continues, planners must consider reliability and economics at the regional level, not just at the local service area level historically considered by utilities. In fact, FERC has encouraged system planners to look even further, and now requires inter-regional coordination.[11] Developing a comprehensive regional or inter-regional electric infrastructure plan requires coordination between and input from various stakeholders at all levels, including local distribution utilities, transmission owners, state and local governments, merchant generators, customer advocates, and environmental groups, among others. Managing regional planning also increasingly involves balancing state public policy goals (i.e., development of renewable resources through Renewable Portfolio Standards ("RPS")) with regional needs and goals. Managing a complex process such as system planning (either at the regional or inter-regional level) requires simplifications that allow for timely and effective decision-making. However, simplifications that result in a failure to evaluate the comparative benefits and costs of MRAs and transmission solutions on equal footing can result in inefficient decisions that could possibly undermine system reliability in the long-term.

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discussed in more detail in Chapter 2. *See:* FERC Order No. 1000. Issued July 21, 2011. 136 FERC ¶ 61,051. <http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf>. P1.

[9] Ultimately, there is little practical difference between an ISO and a RTO; therefore, they will collectively be referred to as "RTOs" from this point onward in this report and from time to time, the terms are used interchangeably.

[10] The Brattle Group. *A WIRES Report on the Benefits of Electric Transmission.* July 2013.

[11] FERC Order 1000 requires coordination between "transmission providers in neighboring transmission planning regions with respect to transmission facilities that are proposed to be located in both regions, as well as interregional transmission facilities that are not proposed that could address transmission needs more efficiently than separate intraregional facilities." *See:* FERC Order No. 1000. Issued July 21, 2011. 136 FERC ¶ 61,051. <http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf>. P 293.

Technology as a driver for change

In addition to policy evolution, technological change has expanded the potential set of solutions to the identified needs of the market and transmission system. System planners now have more options (or at least, a different set of options) than their predecessors had years ago under a vertically integrated regulated industry paradigm. For example, conservation, energy efficiency, and demand response have been recognized as possible solutions for certain resource adequacy and system needs. Furthermore, technological advances have made large-scale renewable energy resources, such as wind and solar, cost competitive. These renewable technologies have also been bolstered by public policy – many states have set goals for renewable energy usage, and at the federal level, these technologies have been supported by tax and/or production credits. In recent years, the focus on the potential contributions that can be made by these technologies has increased, in part due to technological advancements that have improved the capabilities and cost-effectiveness of the technologies, and in part due to the fact that restructured, wholesale power markets provide pathways for the private sector to finance such initiatives and programs to the benefit of the overall system and customers. That said, the characteristics of such alternative solutions will vary from those of transmission, creating challenges in the evaluation of the options and identification of a preferred solution that truly maximizes the benefits to customers in the long-term.

FERC Order 1000 mandates consideration of MRAs

FERC, through Order 1000, issued in 2011, now requires consideration of MRAs in transmission planning.[12] As transmission providers across the U.S. work to comply with Order 1000, and discussions about MRAs occur in wholesale power markets and among state regulators, a few key questions have arisen:

- What exactly is an MRA?
- What services can MRAs provide to customers and the power system? What services are MRAs unable to provide?
- What benefits can MRAs provide? What are the challenges and limitations associated with MRAs?
- How can transmission planners effectively incorporate MRAs into the planning process?

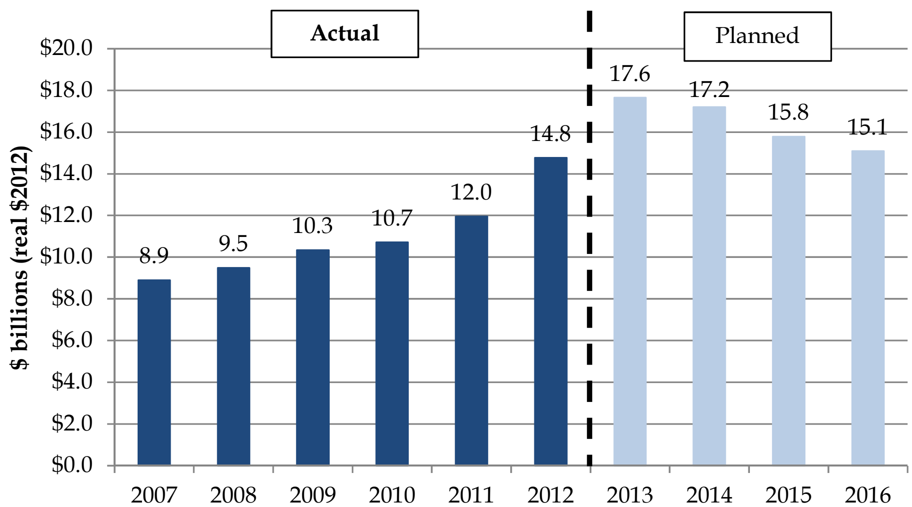
[12] FERC refers to MRAs as non-transmission alternatives. As noted earlier, this is a misnomer that incorrectly implies that MRAs can fully replace transmission. Therefore, in this paper we will use the more accurate term market resource alternatives (MRAs).

We hope that this Report can provide answers to these basic questions. Specifically, the first three questions are addressed in Chapter 1 and then contextualized in Chapters 2 and 3 with experiences to date. Chapter 4 then addresses the last question.

Why is consideration of MRAs important?

Electricity is an integral part of our daily lives, and it is used in virtually every sector of the economy to produce services and final products. The energy industry is the third largest industry in the U.S.,[13] and billions of dollars are spent each year on transmission investments alone, a trend that is expected to continue in coming years (see Figure 6).

Figure 6. Actual and Planned Transmission Investment in the U.S.



**Planned total industry expenditures are preliminary and estimated from data obtained from the EEI Transmission Capital Budget & Forecast Survey, supplemented with data obtained from company 10-K reports and investor presentations. Actual expenditures are from EEI's Annual Property & Plant Capital Investment Survey and FERC Form 1 reports.*
***Data are for investor-owned utilities and do not include transmission investment by cooperative, municipal, state and/or federal power agencies, as well as some merchant developers.*
Source: Edison Electric Institute, Business Information Group. "Actual and Planned Transmission Investment by Investor-Owned Utilities (2007-2016)." May 2014.

In recent years, increasing attention has been given to MRAs given advancements in technology, policy evolution, and the basic need for transmission investment to maintain, modernize, and expand the grid. For example, stakeholders may advocate for MRAs as important tools for meeting policy goals, or as a way for customers to realize cost savings in the long-term, as well as a way to allow customers to exert more choice in how their power is

[13] US Department of Commerce. "The Energy Industry in the United States."
<http://selectusa.commerce.gov/industry-snapshots/energy-industry-united-states>

supplied. However, customers and system planners must also recognize that MRAs are rarely workable substitutes for transmission. In fact, in some cases, MRAs may undermine reliability when viewed in the context of the larger system in the long term. This is because, in general, no MRA is able to provide the full suite of services and benefits that can be provided by transmission.

System planning is not a high-level, generalized problem – it involves detailed analysis to identify the needs of the future system. Such needs may be multi-faceted. Addressing these multi-faceted needs requires consideration of the benefits and challenges of each viable solution. For example, as we will discuss in detail later in this Report, some transmission investments can provide valuable ancillary services to ensure the reliability and effective grid operations; however, an MRA solution (such as energy efficiency initiatives) may not be able to provide these services. 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 system.

Organization of the Report

As mentioned earlier, the Report seeks to address two objectives. The first objective is to develop an understanding of MRAs in the context of system planning (including benefits and shortcomings of MRAs). The second objective is to then consider how MRAs can be effectively evaluated during the transmission planning process. In addressing these objectives, the Report should provide a critical foundational layer of understanding for transmission planners, as well as policymakers and regulators who must endorse and/or authorize the projects that transmission planners propose.

In **Chapter 1** of this Report we begin with a very simple question: what is an MRA? Market resource alternatives - a broad and rather generic term - describes a group of solutions to identified electric system needs that do not involve traditional transmission infrastructure. Although there is not a clear definition of what technologies are considered to be MRAs, discussions of MRAs occurring in wholesale power markets and at state regulatory commissions generally focus on six categories of MRAs: energy efficiency; demand response; utility-scale generation; distributed generation; energy storage; and smart grid technology. We describe in detail the characteristics of these MRAs, and their benefits and challenges from a system planning and operations perspective. Specifically, we consider the types of services and benefits that these MRAs can provide relative to the broad range of services and benefits provided by transmission. Understanding the characteristics of MRAs is critical for system planners, who must ultimately be able to evaluate MRAs alongside transmission in order to select the investments that best meet the needs of the system. Consideration of the dimensions of service and the qualities of MRAs relative to more in-depth consideration of benefits is also important to ensure that the appropriate analytical tools and techniques that fully consider all aspects of the benefits offered by transmission and MRAs are deployed. Our examination of MRAs and the services and benefits they provide relative to transmission has shown that individual MRAs typically provide many benefits but even then, it is based on a partial suite of the services that transmission provides. Furthermore, our investigation into MRAs highlighted the importance of considering externalities (both positive and negative) in any analysis used to evaluate MRAs and transmission. For example, does the solution catalyze other investment opportunities that benefit customers? This could be characterized as a positive externality. Or, on the other hand, does the solution require incremental investment, or create other costs for the system and customers? This would then be a negative externality.

In **Chapter 2,** we describe in summary form the federal and regional policies surrounding MRAs, including FERC Order 1000. Among the many transmission planning and cost allocation issues covered in FERC Order 1000, it requires consideration of MRAs in the regional transmission planning process. However, it does not establish any requirements as to which MRAs should be considered or what the appropriate metrics for evaluating MRAs against transmission solutions would be. To provide additional context, we consider how MRAs are currently being treated by system planners across the country as they work to comply with FERC Order 1000. We also consider in summary form how MRAs are treated in regions that are not part of an RTO. We found that MRAs appear to generally be considered in the transmission planning process in RTOs, although the timing of this consideration and the extent to which MRAs are evaluated varies on a case-by-case basis. Generally, evaluation of MRAs completed to date appears to be targeted and localized, rather than comprehensive. This is not surprising as economic analysis of transmission is also a relatively nascent but evolving component of the system planning process. Nonetheless, there are few examples of the explicit consideration of MRAs in planning analyses to date, which we describe in Chapter 2 for the sake of illustration of current practices.

In **Chapter 3**, we perform a case study review of several specific examples of how MRAs have been incorporated in the planning process. In the process of selecting the case studies, we reviewed many possible case studies and settled on four examples that, when taken together, cover a variety of MRA technologies and investment needs, apply varying levels of analytical techniques for consideration of MRAs and transmission solutions, and highlight different aspects of the interplay between MRAs and transmission investment. Specifically, we considered the following case studies in this case study review of MRAs: Boothbay Smart Grid Reliability Pilot project in Maine, I-5 Corridor Reinforcement Transmission Project by Bonneville Power Administration ("BPA"), PATH and MAPP transmission projects in PJM, and Tehachapi Renewable Transmission Project in California. Although there were a number of different MRA technologies considered, and the "need" driver behind the projects varied, we identified several observations from these case studies that were used to inform the development of a recommended set of analytical tools and techniques for evaluating MRAs alongside transmission. The major observations from the case studies include the following:

1) A feasible MRA should be judged on the same criteria for reliability and economic benefits as proposed transmission.

2) The ability of MRAs to consistently meet the technical (reliability) needs of the system are sometimes overlooked for the sake of policy – technical feasibility should be a requirement, not an option, of a thorough evaluation.

3) In order to fairly compare feasible investment options, the evaluation framework must assess a broad set of benefits and costs.

4) A robust cost-benefit analysis should measure and quantify the uncertainties and risks associated with MRAs and transmission. In other words, the analysis should consider the "insurance" value an MRA or transmission can have to hedge against future uncertainties and risks.

5) MRAs and transmission are not equal in the services and benefits each can provide – a more comprehensive analysis of the various services and resulting benefits should be undertaken in order to select the options that maximize benefits to customers.

6) Economic cost-benefit analysis should consider the dynamic evolution of the system. Such an analysis would show, on an objective and non-discriminatory basis, the potential impacts of new investment on the system and customers. In addition, such an analysis may identify complementary relationships between transmission and certain MRAs, which could justify the need for more investment.

Finally, in **Chapter 4**, we draw on the key observations from current practices across the U.S., the case studies, and methodologies and concepts commonly used in economic analysis of investment to provide recommendation on a set of analytical tools and techniques (which we refer to as the "toolkit") that can be incorporated as appropriate into a cost-benefit analysis to effectively evaluate transmission and MRAs within the system planning process. There are three critical components to this toolkit and the cost-benefit framework: (1) identification of benefits and costs that need to be considered, (2) selection of the analytical tools, and (3) consideration of techniques for analysis that will properly assess the technical attributes of a solution and reflect the time and geographical dimensions of benefits and costs, and the uncertainty in key drivers. In Appendix A, we have included a description of that provides an example of an approach in which the identified tools and techniques could be combined to evaluate MRAs in system planning process.[14]

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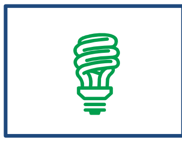
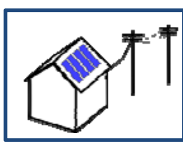
[14] It is important to note that this Report does not address the matter of if and how MRAs should be treated for cost allocation purposes. Such an analysis is beyond the scope of this paper.

Chapter 1: What are Market Resource Alternatives?

MRAs is a broad and rather generic term, which is intended to represent a group of solutions to identified electric system needs that do not involve traditional transmission infrastructure. Although FERC Order 1000 requires MRAs be considered in transmission planning, it does not define the technologies that would be considered an MRA.

MRAs come in a variety of forms and can include supply-side resources (for example, conventional generation and distributed generation or advanced generation-like technologies such as batteries and storage) and demand-side resources (such as demand response and conservation/energy efficiency programs), or a combination of resources that are not conventionally associated with transmission. More recently, the term "MRAs" have even included smart grid distribution technologies. Discussions of MRAs occurring in wholesale power markets and at state regulatory bodies generally focus on six categories of MRAs: energy efficiency; demand response; utility-scale generation; distributed generation; energy storage; and smart grid technology (see Figure 7).

Figure 7. MRA Categories

	Energy Efficiency	improvements that result in the ability to use less energy to provide end-use customers with the same (or a better) level of service in an economically efficient way
	Demand Response	changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time or to incentive payments
	Utility-scale Generation	relatively large generators that connect to the grid at the transmission (high voltage) level
	Distributed Generation	small generation systems located at a customer site
	Energy Storage	technologies that allow electricity generated at one time to be used at another time
	Smart Grid	technologies that enable a more efficient use of the electric power grid through computer-based remote control and automation

1.1 MRAs and System Planning

System planning is a complex task in which planners must optimize investment in an array of technologies that together create a reliable system. Moreover, the electric system is not a single machine but rather a sum of different technologies working together. Therefore, even in a planning environment, there cannot be a singular focus on one technology to the exclusion of others. For example, the system needs both generation and transmission. Transmission can only provide capacity services if the output of generators is available for transport from an area of surplus to one that is capacity deficient. Likewise, generation can only supply energy if there is transmission in place to transport the energy to areas of demand. The electric system also needs load and customers that will use the electricity productively.

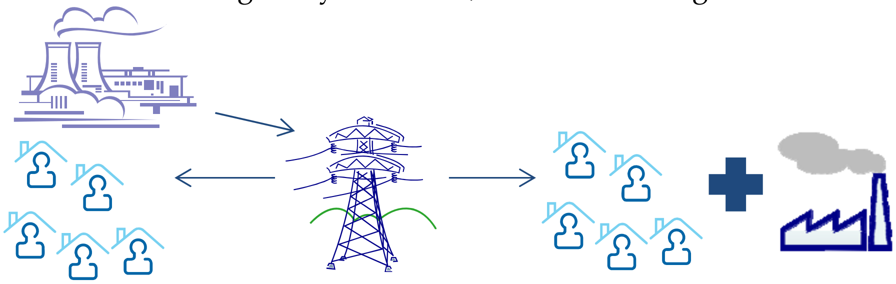
In the context of the electric power system planning process, MRAs can be broadly considered as programs or technologies that complement the transmission system and provide benefits similar to those provided by the transmission system. But some MRAs may face limitations that prevent them from providing the full suite of services and benefits that are created as a result of transmission investment. As an illustrative example, let's assume that a system planner has identified a need for transmission reinforcements in the future because of reliability violations due to increasing and diversifying load in a particular region - in this case, a new factory opens in the area and the load requirements increase (shown in Figure 8).[15] An MRA, if it can solve the reliability problem, could in theory be used in place of the transmission solution.

For simplicity, in this Chapter we describe transmission and each MRA independently. However, we recognize that any reliable system will require a variety of technologies. The challenge for the regulators and planners is striking the right balance, not simply picking the "best" technology. In order to put the benefits of each MRA in context, we first provide a description of the services and benefits transmission provides. Understanding the types of services and benefits MRAs can provide relative to transmission is necessary to determine the types of analytical tools and techniques that should be deployed to effectively evaluate MRAs alongside transmission. Therefore, we start this Chapter with a review of the services and benefits that transmission can provide.

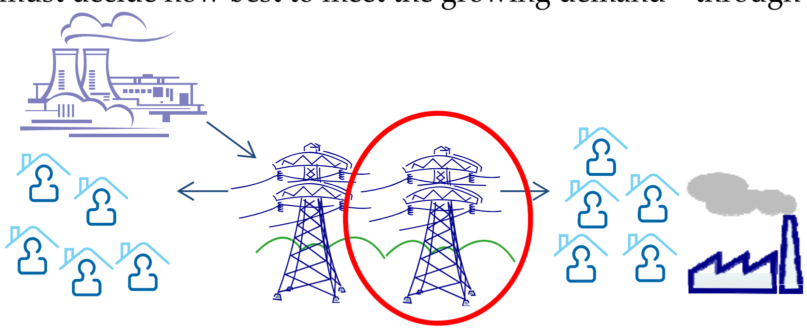
[15] LEI recognizes that in some regions demand may be growing a slow rate, or not at all. However, there are numerous instances in which load is diversifying as new business and industries set up in different areas.

Figure 8. MRAs and System Planning

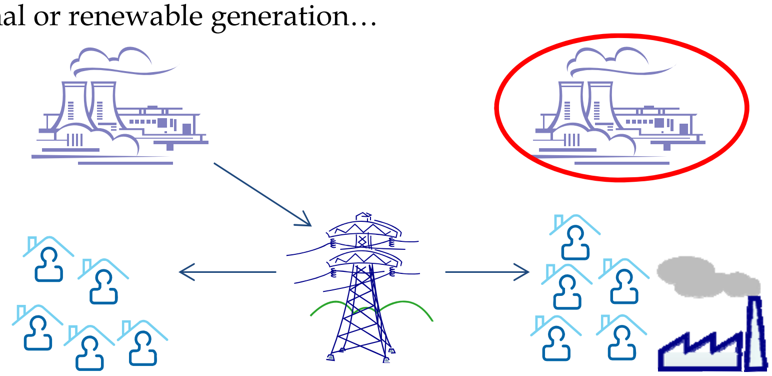
Current infrastructure is meeting today's demand, but as load and generation diversify



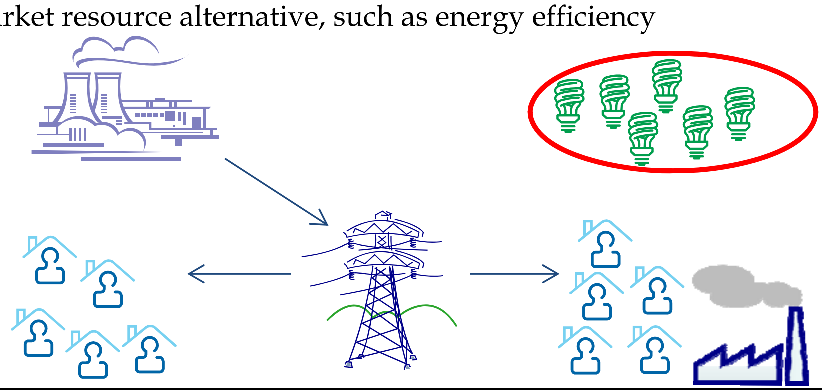
system planners must decide how best to meet the growing demand – through transmission…



…new conventional or renewable generation…



…or another market resource alternative, such as energy efficiency



1.2 Services and Benefits Provided by Transmission

Transmission solutions can be provided by a combination of technologies and applications on the grid: transmission line solutions, transmission terminals or substations upgrades or additions, and devices that enhance control of the grid. As technologies have evolved, so has the ability for newer materials to be combined with electrical engineering solutions to solve for multiple needs (i.e., reliability, market efficiency, public policy). More recently, technological advances in the ability to control the flow of electricity on the grid have created incremental opportunities to enhance reliability and further strengthen the resilience of the grid, as well as improve economics (by reducing congestion and allowing for higher volume of trading through the ability of the lines to carry heavier flows, etc.).

> **Examples of Transmission Solutions**
>
> **Line Solutions:**
> - ***High voltage alternating current ("AC"):*** direction of electric flow changes over time
> - ***High voltage direct current ("DC"):*** electricity flow is constant and moves in one direction
> - ***Line upgrades***
> - ***New lines***
>
> **Control-Enhancing Solutions:**
> - ***Voltage source converters:*** devices that convert AC to DC (or vice versa)
> - ***Phase angle regulators (or phase shifting transformers):*** specialized transformers used to control power flows

What services does transmission provide?

Transmission provides for the transportation of electric power from producers (generators) to customers (load), often times over long distances. In addition to facilitating the delivery of energy and capacity, transmission can provide other benefits. For example, transmission system reinforcements can reduce system losses and provide support to the electric power grid through the provision of certain ancillary services, which are used to keep the grid operating smoothly. Transmission can provide insurance against uncertain future market events and reduce production costs of energy through expansion of a market (and more competition) and provision of market access to new resources. Furthermore, transmission is a long-lived asset capable of providing benefits for decades. It is important to consider to what extent MRAs can produce these same services, over what time dimension they can be counted on to provide these services, and for what geographical area. In many cases, MRAs may have shorter economic lives (or less certain longevity) than transmission, and provide benefits to a smaller or more localized geographical segment of customers. One way to think about MRAs in this context is by considering a few questions:

- ***What* service does transmission or the MRA provide?** Transmission provides energy, capacity, and ancillary services, as well as other benefits for customers and the system as a whole. Which of these services and benefits does the MRA provide? Can MRAs provide all these services or there are some technical limitations for MRAs to provide certain services/benefits?

- ***When* does transmission or the MRA provide the service?** Transmission infrastructure is a long-lived investment (with a useful life measured in decades), and is capable of providing services on a continuous basis (i.e., all day, every day). Is an MRA able to provide the service on a continuous basis? What is the longevity (permanency) of the MRA solution?

- ***Where* does transmission or the MRA provide the service?** Transmission can cover long distances, serving both local and regional needs. What is the extent of the MRA's impact in geographical terms – regional, local, or micro (i.e., customer site)?

- ***How* does transmission or the MRA provide the service?** Transmission is implemented at the system/wholesale market level rather than at the customer/retail market level, and is therefore able to affect more customers. Transmission can participate in wholesale power markets (energy, capacity). Furthermore, given the scale of transmission, it also typically provides greater indirect economic benefits (i.e., jobs created) than customer/retail solutions that have a more narrow impact.

Figure 9 provides a high level overview of the dimensions of the services provided by transmission classified in terms of product, time dimension, and geographical scope. The black circles indicate that the service is fully provided, while white (or empty) circles indicate that the service is not provided.[16] As mentioned earlier, we recognize that this type of comparative chart can simplify the relationship between transmission and MRAs. Transmission and MRAs are interconnected – a system comprised of one or the other would not be functional. In this sense, transmission can only provide energy and capacity if there is a generator connected to the grid able to generate the energy and capacity. Likewise, generation can only provide energy and other services if there is a transmission system that connects the generator to customers. As we describe the MRAs in the following sections, we will use a similar graphic to consider to what extent each MRA can provide these same services. This comparison is meant to reflect the relative abilities of generic MRAs and generic transmission investment to provide broad classes of services. In reality, the specific services will vary with the characteristics of the individual project (i.e., proposed solution) and the underlying "need."

Furthermore, the comparative charts of transmission and MRAs in the following sections reflects overall experience of LEI and WIRES members with the technologies as they exist today. We recognize that technology (both MRAs and transmission) is evolving rapidly, and that MRAs and transmission will likely be able to provide a more extensive list of services in the future. Nevertheless, the comparison of relative abilities under the current technology is useful. The comparison provides a high level consideration of relative strengths and weaknesses of different MRAs, from which benefits can be evaluated. Such a comparison of services is also useful cross-check for the toolkit, which needs to contain tools and techniques that can capture differences in services provided, technical characteristics, and ultimately economic costs and benefits.

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[16] Partial shading indicates the extent to which the service is provided – for example, a ¾ shaded circle indicates that the service is provided in most instances.

Figure 9. Services Provided by Transmission

		Transmission
What	Energy	●
	Capacity	●
	Ancillary Services	●
	Reduce system losses	●
When	Long lifespan	●
	Continuous basis	●
Where	Regional	●
	Local	●
	Micro	●
How	System/Wholesale	●
	Customer/Retail	○

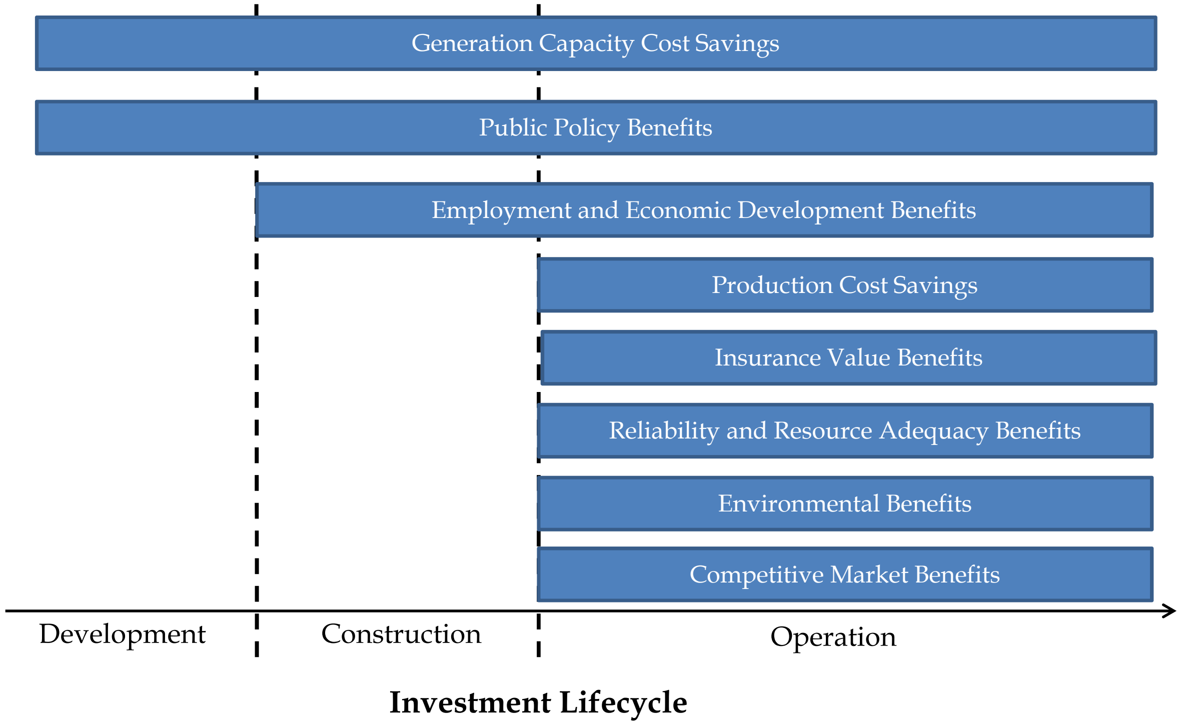
● Provided ○ Not provided

What benefits does transmission provide?

As discussed above, in order for an apples-to-apples evaluation, a feasible MRA should be judged on the same criteria for reliability and economic benefits as the proposed transmission solution. While there is consensus among system planners to employ a similar approach to evaluating the reliability impacts of proposed transmission and MRAs (based on NERC standards), the economic criteria used for evaluation of transmission and MRAs varies greatly. That said, system planners commonly deploy simulation modeling techniques for economic evaluation of transmission, and these same modeling tools can and should be employed for assessment of MRAs. The application of the same tools and consideration of similar metrics will allow system planners to objectively weigh benefits and costs of various alternatives.

WIRES has done a considerable amount work to identify the wide range of potential benefits that transmission investments can offer over their lifetime. These potential benefits begin in the development stage, carry on during construction, and continue once projects are operational (as presented in Figure 10).[17]

Figure 10. Potential Benefits of Transmission Investments Identified by WIRES



Note: the ordering of the benefits in the chart above does not reflect the relative magnitude of benefits

MRAs should be evaluated against the same categories of potential benefits and services created by transmission investment, which are described in detail below:

- **Generation capacity cost savings:** transmission projects result in savings from deferring or avoiding investment in generation assets. These savings are often timed with the development stage of a transmission project – once it has been identified and approved, a transmission project may impact the investment decision for generation assets, and vice versa.

- **Public policy benefits:** these benefits include helping to meet policy goals such as RPS targets. For example, as we discuss further in Chapter 3, transmission may sometimes be developed to spur investment in renewable generation projects. Similar to generation capacity cost savings, these public policy benefits can start to accrue even in the development stage of a new infrastructure investment, since the identification and

[17] The Brattle Group (Chang, Pfeifenberger, and Hagerty), *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, prepared for and prefaced by WIRES, July 2013

approval of a transmission project can impact the investment decision for generation assets and other MRAs, and vice versa.

- **Employment and economic development benefits:** these benefits include expansion of local employment and increased economic activity in the region/state where an infrastructure investment is constructed due to local capital and O&M spending by the project sponsor. Both transmission investments and MRAs can in principle produce such benefits but the scale of the benefits will vary with the size of investment, and the scope of geographical distribution of electricity market impacts. Notably, employment and economic development benefits can be captured during the construction and operations phases of investment.

- **Production cost savings benefits:** by expanding the market, transmission projects allow for an increase in the dispatch of lower cost suppliers, resulting in a more efficient system and in lower costs of electricity. These savings are realized once the transmission project is operational. Some MRAs may create an opportunity for production costs savings and lower costs of electricity, as well, but the magnitude (scale), geographical footprint (and which customers are affected) and longevity of those benefits may differ from that of transmission.

- **Reliability and resource adequacy benefits**: once operational, transmission projects can increase the resiliency and reliability of the system by increasing flexibility, reducing the risk of load shed, and increasing options for recovering from interruptions to supply. Furthermore, transmission projects increase access to generation resources including resources in neighboring regions, which helps ensure resource adequacy and reduces required capacity reserves/margins.

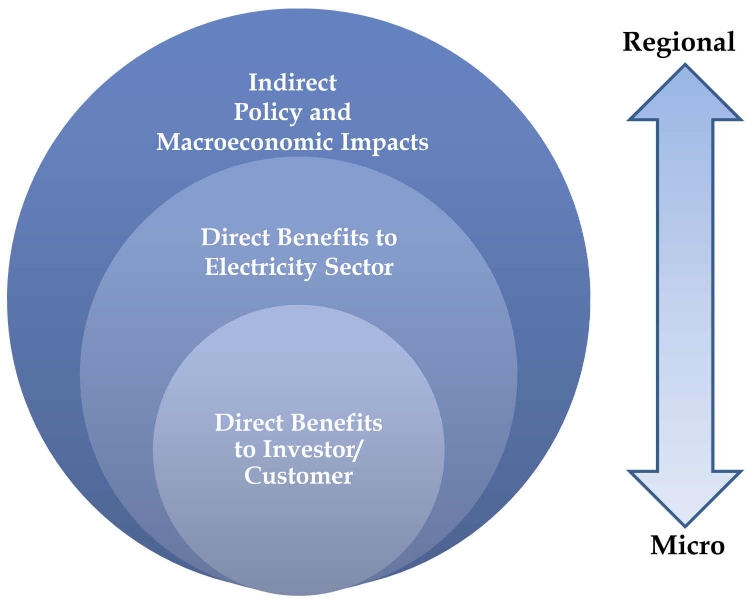
- **Environmental benefits:** once operational, transmission projects can bring environmental benefits such as reduced greenhouse gas emissions and reduction of other pollutants by expanding the system operators' generation dispatch options and improving overall system efficiency. Similar to the environmental benefits that arise as a result of transmission providing access to a wider variety of generation sources, MRAs can displace higher emitting resources and therefore create such benefits. However, the scale and geographical scope of such benefits may be smaller than that of a transmission investment.

- **Competitive market benefits**: during the operation phase, transmission projects can provide market benefits through increased competition and market liquidity. Transmission expands the market - by increasing the number of market participants, transmission reduces market concentration and increased competition. The market benefits of transmission can be seen in reduced transaction costs and improved price transparency.

Considering the differences in MRAs' and transmission's ability to provide benefits

When we consider if and how MRAs are able to provide these equivalent benefits of transmission, we will also consider any challenges that impact the ability of MRAs to deliver these benefits (or for system planners and operators to take advantage of these benefits). Not only do we need to understand which of these benefits MRAs can provide, we also need to consider the magnitude and breadth of the benefits. Transmission provides a broad array of benefits that accrue to a wide variety of parties over a large geographical dimension. That is, the benefits accrue at a micro or local level (for example, to the investor), but transmission also directly benefits a broader set of customers in the electricity sector and indirectly creates benefits for society as a whole, for example through achievement of public policy and macroeconomic benefits (see Figure 11).

Figure 11. Magnitude and Breadth of Benefits

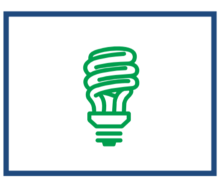


Furthermore, transmission consistently provides these benefits throughout its lifecycle. That is, for some benefits, system planners have ***reasonable certainty*** that these benefits will accrue over the transmission asset's life. In other words, once a transmission project is built and brought online, there is usually little risk that it will be retired or mothballed due to evolving market conditions or circumstances of the project sponsor. As we will discuss in the following Chapters, experience has shown that there is a higher degree of uncertainty associated with MRAs, both in terms of the services and the benefits they can provide. Demand-side MRAs require ongoing modification of consumer behavior which may not be sustainable. Some MRAs may also cause unintended consequences for the functioning of electric markets. For electric transmission infrastructure investments, however, the greatest uncertainties arise as a result of the initial development process, particularly when a system enhancement requires siting in environmentally sensitive locations. Once the initial development uncertainties are resolved at the outset of an asset's life cycle, long-term system benefits are relatively certain. For example, experience in Germany has shown that while MRAs bring benefits in the short-term, in the long-term they may create negative consequences for the market. In Germany, large amounts of subsidized intermittent distributed generation drove wholesale prices down, causing flexible gas-fired resources to exit the market.[18] Without these resources to balance the intermittent distributed resources, the grid faced stability and reliability issues, and was negatively impacted in the long-term.

Finally, when considering the benefits of transmission or MRAs, it is important to consider the secondary consequences and embedded options associated with the investment. These can be either positive or negative: for example, if a solution can provide an option to delay other investments or an option for future expansion, that would have a positive value to customers and system planners alike. On the other hand, if a solution requires additional incremental investment to come online (perhaps in the form of additional infrastructure), that cost should also be considered.

1.3 MRA Categories

Each MRA has different characteristics that can be viewed as beneficial or challenging to the identified need and goal of system planners. Understanding these characteristics is important in determining whether MRAs can truly substitute for, defer or even eliminate the need for, certain traditional "wires" investments in the transmission system. The following sections describe each of the six categories of MRAs in more detail, provide a brief summary of how each MRA is currently used in the U.S. markets, the services each MRA can provide, and give an overview of the potential benefits and challenges associated with each MRA. Each description concludes with a summary of the services that the MRA can provide relative to transmission using a chart similar to the one presented in Figure 9 on page 32. As discussed earlier, these charts provide an indicative, general comparison of the relative abilities of an MRA based on the experience of LEI and WIRES. We acknowledge that the comparative benefits or limitations may be different in individual instances, and will likely evolve over time as technology gains expand the breadth and depth of MRA technologies and transmission solutions.



1.3.1 Energy Efficiency

Energy efficiency ("EE") refers to improvements that result in the ability to use less energy to provide end-use customers with the same (or a better) level of service in an economically efficient way.[19] Energy efficiency results

[18] Harvard Business Law Review. The Challenge of Distributed Generation. 2013; *See also:* Fraunhofer Institute for Solar Energy Systems.

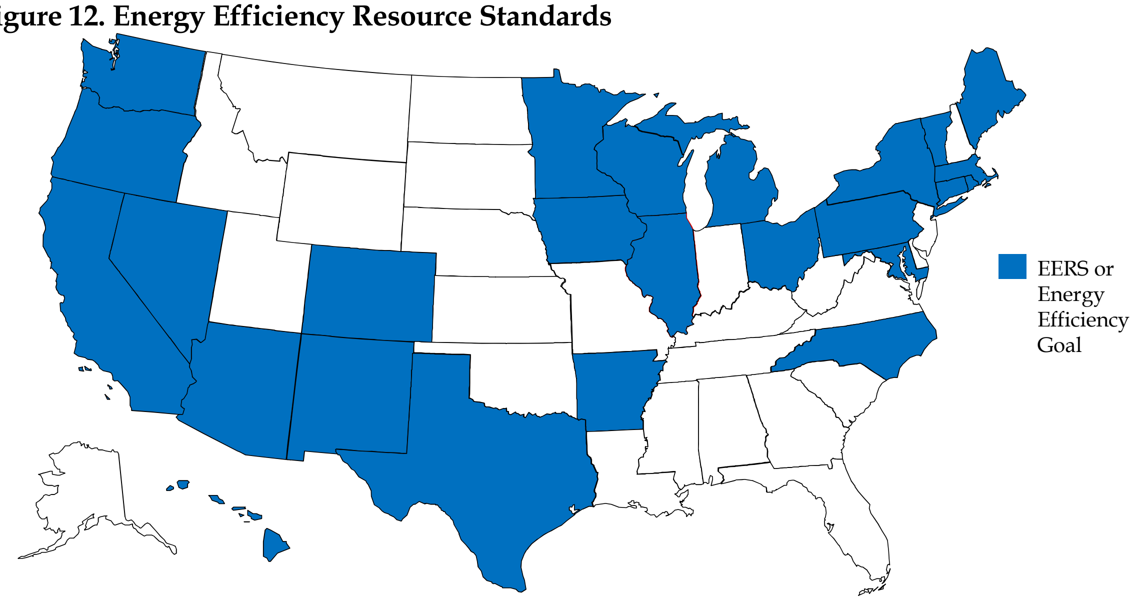
[19] "Energy efficiency refers to using less energy to provide the same or improved level of service to the energy customer in an economically efficient way; it includes using less energy at any time, including during peak periods." *See:* Ernest Orlando Lawrence Berkeley National Laboratory. *Coordination of Energy Efficiency and Demand Response.* January 2010.

in permanent changes to electricity consumption, typically through technology upgrades. Households, for example, can replace old appliances with more efficient appliances that use less electricity. At a higher level, local and state governments can incorporate energy efficiency criteria into building codes (for example, requiring non-residential locations to install lighting controls) so that less electricity is used in the future.

There are well-established energy efficiency policies at the federal, state, local, and utility level. The policies focus on several main areas of energy efficiency such as appliance or equipment standards, energy standards for public buildings, and building codes.[20] Currently, 25 states have Energy Efficiency Resource Standards ("EERS") and several others have energy efficiency goals (see Figure 12).[21]

An EERS is similar to a RPS; it establishes long-term targets (which typically range from 1-2% of annual sales) for energy savings that utilities or program administrators are required to meet through customer energy efficiency programs. In fact, some RPS' explicitly include energy efficiency targets. In addition to energy efficiency policies, a variety of financial incentives are offered to customers who undertake energy efficiency improvements.

Figure 12. Energy Efficiency Resource Standards



Source: ACEEE.

As an MRA, energy efficiency is typically deployed as a way of meeting electricity demand in a local, transmission-constrained load pocket. As a result of energy efficiency efforts, less energy

[20] DSIRE. "Rules, Regulations & Policies for Energy Efficiency" <http://www.dsireusa.org/summarytables/rrpee.cfm>

[21] Utah and Virginia both have voluntary standards. *See:* ACEEE. *State Energy Efficiency Resource Standards.* April 2014. <http://www.aceee.org/files/pdf/policy-brief/eers-04-2014.pdf>

is used during many (or even all) periods of time (rather than just reductions during super-peak demand, which is a feature typical of demand response). Energy efficiency therefore results in a reduction in total electricity consumption, in contrast with other demand-side MRAs that result in shifting of demand across time (e.g., demand response, demand-side management, and distributed generation from intermittent resources).[22] Capturing the benefits of energy efficiency typically requires little investment or change to current transmission infrastructure and/or market rules.

One of the key challenges associated with energy efficiency is accurately forecasting future energy efficiency penetration and its durability or longevity. The forecast methods historically used by utilities (simply subtracting efficiency savings from demand) tend to overestimate the demand reduction caused by energy efficiency, since some of the efficiency savings are already accounted for in the demand forecast.[23] This results in low demand forecasts, which, when used for long-term system planning, may send incorrect signals about the need for new investment in the market. Further complicating forecasting, energy efficiency initiatives may result in an unintended *increase* in load rather than load reduction. For example, a rebate on energy efficient air conditioners may entice people who never previously owned an air conditioner to purchase a new air conditioner. If enough new customers purchase air conditioners as a result of the rebate, this new load would offset or potentially exceed the load savings represented by customers that already owned air conditioners and used the rebate to replace them with more efficient models.

Energy efficiency can provide some of the services that are provided by transmission, but generally not to the same extent (see Figure 13). Energy efficiency resources can provide energy (by reducing load) and in some regions, energy efficiency is also associated with capacity benefits (if the energy efficiency can reliably reduce load during system peaks). Energy efficiency can also reduce system losses via load reduction (and indeed, in some markets, energy efficiency is given explicit "credit" for the loss reduction).[24] However, as noted above, the load reductions are not always certain, and sometimes difficult to predict and verify (measure). Moreover, in terms of capacity, the performance of energy efficiency may not be as responsive to the real-time needs of the system as other resources. For example, if a system stress event occurs during time periods that would not typically have been affected by the energy efficiency initiative, there may not be any contribution from such energy efficiency resources in helping the system recover from the stress event. In addition, energy efficiency cannot provide ancillary services. On the other hand, energy efficiency resources have a relatively long lifespan, and are able to perform on a continuous basis. However, shifts in

[22] Distributed generation also has the ability to reduce demand and change load shape, a feature that differs slightly from changes in load due to demand response.

[23] ACEEE. *Summer Study on Energy Efficiency in Buildings*: *Integrating Energy Efficiency into Utility Load Forecasts*. 2010.

[24] In ISO-NE, demand resources are credited for avoided peak transmission and distribution losses. *See:* ISO-NE. Market Rules § III.13.7.1.5.1.

consumption patterns may limit their efficacy. Also, in the context of market-procured energy efficiency, there is always a risk that the resource may exit the market if the opportunities in the market fall below the opportunity costs of continued operation. Energy efficiency occurs at the customer level, and is most impactful at the micro or local levels of the grid.

Figure 13. Services Provided by Energy Efficiency

		Transmission	Energy Efficiency
What	Energy	●	◑
	Capacity	●	◑
	Ancillary Services	●	○
	Reduce system losses	●	◑
When	Long lifespan	●	◕
	Continuous basis	●	◕
Where	Regional	●	◑
	Local	●	●
	Micro	●	●
How	System/Wholesale	●	○
	Customer/Retail	○	●

● Provided ○ Not provided

1.3.2 Demand Response

Demand response ("DR") refers to end-use customers changing their consumption patterns in response to power grid needs, economic signals from a competitive wholesale market, and/or a special retail rate. DR lowers demand during discrete periods of time (i.e., reduction in consumption during peak load conditions or under specific system events that impact system reliability).[25]

[25] FERC defines demand response as "changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized." *See:* FERC. "Reports on Demand Response and Advanced Metering." <https://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp>

There is a wide variety of demand response programs currently in place. Typically, demand response mechanisms are driven by either economic or reliability issues. Economically-driven DR resources are usually triggered when prices reach a certain threshold. Reliability-driven DR resources, on the other hand, are typically triggered by operational procedures or automatic responses. In most RTOs there are a variety of demand response programs, including both economically-driven and reliability-driven programs. For example, the different triggers and requirements for each DR program in the MISO market are shown in Figure 14 below. In some cases, resources are required to respond to the trigger, while in other cases the response is voluntary.

Figure 14. Demand Response Products in MISO

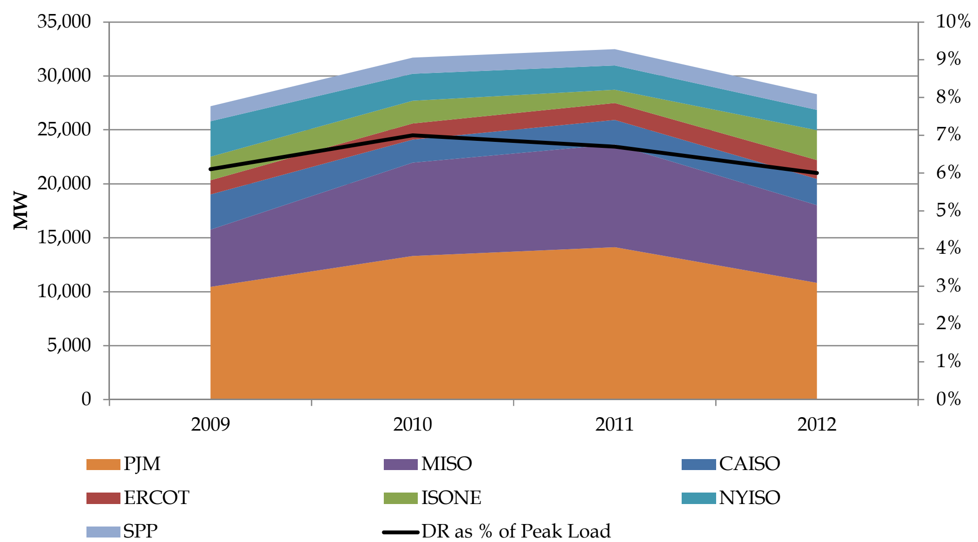
Product	Service Type	Response Required	Primary Driver	Trigger Logic
Demand Response Resource Type I (Energy)	Energy	Voluntary	Economic	Energy price > Offer price
Demand Response Resource Type I (Reserve)	Reserve	Mandatory	Economic	Energy price > Offer price
Demand Response Resource Type II (Energy)	Energy	Voluntary	Economic	Energy price > Offer price
Demand Response Resource Type II (Reserve)	Reserve	Mandatory	Economic	Energy price > Offer price
Demand Response Resource Type II (Regulation)	Regulation	Mandatory	Economic	Energy price > Offer price
Emergency Demand Response	Energy	Voluntary	Reliability	Operational Procedure
Load Modifying Resource	Capacity	Mandatory	Reliability	Operational Procedure

Source: ISO/RTO Council. *North American Wholesale Electricity Demand Response Program Comparison.* February 2014.

In economic, or price-based, DR programs, end-use customers voluntarily limit consumption in response to high prices. In reliability, or event-based, programs, customers may allow their utility some control over certain equipment (for example, the utility can "cycle" – turn off and on - certain appliances such as air conditioners and pool pumps during periods of peak demand) or they receive payments in return for a commitment to reduce load during specific periods. In event-based programs, demand response is activated in reaction to pre-determined triggers such as grid congestion, operational reliability requirements, and system economics, among others. Event-based (reliability-driven) demand response programs account for the majority of capacity participating in the demand response programs across the U.S. Furthermore, DR programs have historically been better suited for industrial and large commercial customers – sophisticated customers that actively manage their electricity consumption. Residential applications of DR have been more limited, but may evolve in parallel with increasing deployment of distribution-side smart grid technologies.[26]

Currently, demand response resources can participate in a variety of markets across RTOs (depending on the RTO, demand resources may be able to participate in energy, ancillary services, and capacity markets). RTOs generally offer a variety of DR products and the types of resources eligible and the rules governing participation vary across RTOs. In 2012, over 28,000 MW of DR resources were registered with RTOs, representing approximately 6% of the seven US RTOs' peak demand (see Figure 15).[27]

Figure 15. Demand Response in Wholesale Markets



Source: FERC

While favorable changes to market rules and technological advancements have increased opportunities for DR resources to participate in wholesale markets, participation levels have fluctuated in the past, in part due to the returns DR resources expect to earn from the market, and the availability of programs in which DR resources can participate. For example, between 2011 and 2012, PJM experienced a decline in DR resources participating in the market. PJM's market monitor concluded that this decline was driven by two key factors: the decrease in the clearing prices in PJM's forward capacity auction, and the discontinuation of one of PJM's DR products, the Interruptible Load for Reliability program.

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[26] National Council on Electricity Policy. *Updating the Electric Grid: An Introduction to Non-Transmission Alternatives for Policymakers.* September 2009.

[27] FERC. *Assessment of Demand Response and Advanced Metering.* October 2013.

It is important to note that the participation levels are different from performance levels. Participation refers to a resource's registration in a DR program. Performance, on the other hand, refers to how the resource (once registered) responds to dispatch instructions when it is called upon. A challenge in some DR programs is ensuring high performance levels – some programs lack penalties for failure to perform, which gives resources little incentive to perform as promised. This is a concern for system planners, who must evaluate the future benefits of MRAs, which will derive from actual operations more so than design capability.

As an MRA, reliability-driven DR products may be used to balance supply and demand and to ensure reliability during periods of stress on the system. RTOs have successfully deployed DR resources in the past to maintain system reliability during periods of system stress (unusually high load, system contingency events). But such DR resources cannot be called upon frequently and repeatedly. This is one operational challenge of relying on MRAs and should be evaluated in the planning process.

As RTOs and utilities look to procure increasing amounts of DR resources, they are working to address several challenges raised by integrating DR resources. Such challenges include operational issues related to the treatment of DR resources in the capacity and energy markets, as well as payment issues related to the technical challenge in establishing an accurate baseline for measuring the quantity of DR and therefore the payments for service. Another challenge with DR is the variability in available (registered) DR over time and performance of DR resources. It has been shown that with increased use of certain types of demand response products (i.e., load curtailment), customers' interest to continue with the program may wane, because the inconvenience of these curtailments may outweigh participants' perceived benefits, and ultimately, these DR resources may choose not to offer themselves into the market.[28]

Demand Response and FERC

In March 2011, FERC issued Order No. 745, requiring RTOs to compensate DR resources at market-based rates (i.e., the locational marginal price, or "LMP"), given their ability to balance supply and demand as an alternative to generation. On May 23, 2014, the U.S. Court of Appeals vacated FERC Order 745 on the grounds that demand response was a retail transaction and therefore beyond FERC's jurisdiction. It remains to be seen how FERC and the industry will respond.

Source: FERC Order No. 745. Issued March 15, 2011. 134 FERC ¶ 61,187. <http://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf>; US Court of Appeals Docket No. 11-1486. *On Petitions for Review of Orders of the Federal Energy Regulatory Commission.* May 23, 2014

[28] While demand response is fairly well developed in the U.S. markets, it has been slower to develop in other markets. For example, the European Commission found that "demand response is progressing slowly in the [European Union]", with a handful of member states leading the way (France, Italy, Spain, and the United Kingdom). *See:* European Commission. *Incorporating demand-side flexibility, in particular demand response, in electricity markets.* May 2013.

From a service prospective, demand response can provide some, but not all, of the services provided by transmission (see Figure 16). Demand response, like energy efficiency resources, can provide energy and capacity, and can reduce system losses via load reduction (and are allowed to participate in wholesale energy and capacity markets). Demand response can also provide ancillary services such as regulation reserves. However, as with energy efficiency the load reductions are difficult to measure (verify), not always certain and vary over time, and are therefore considered partially provided. Demand response resources have a relatively short lifespan, and do not perform on a continuous basis (demand response resources by definition perform only during certain periods). The volatile participation levels also put additional stress on the system planning. In some jurisdictions, such as ERCOT, system planners have determined that the performance uncertainty of DR or other MRAs makes them infeasible alternatives to reliability-driven transmission projects (see Section 2.1.2 for more information). Lastly, demand response occurs at the customer level, and is most impactful at the micro or local levels.

Figure 16. Services Provided by Demand Response

		Transmission	Demand Response
What	Energy	●	◐
	Capacity	●	◐
	Ancillary Services	●	◐
	Reduce system losses	●	◐
When	Long lifespan	●	○
	Continuous basis	●	○
Where	Regional	●	◐
	Local	●	●
	Micro	●	●
How	System/Wholesale	●	○
	Customer/Retail	○	●

● Provided ○ Not provided

1.3.3 Utility-scale Generation

Utility-scale (or "conventional") generation refers to large centralized generation plants that connect to the grid at the transmission level (as opposed to distributed generation, which connects to the grid at the distribution level). Conventional generation includes nuclear, fossil fuel-fired resources (i.e., natural gas, coal, oil) and renewable resources.

System planners have historically considered conventional generation in the system planning process. However, with the advent of restructuring and competitive wholesale power markets, the generation investment decision is no longer controlled by the planning authorities in those restructured power markets operating within RTOs. Instead, wholesale electric power markets provide the price signals that investors use to decide if/when to build generation. These price signals also lead investors to decide when to retire plants (that is, plants may retire for economic reasons if they do not make adequate revenues in the wholesale power markets). The retirement of plants (either for economic or other reasons) can lead to increased demand in the system, and can present a challenge for system planners.

Conventional generation can be used to address local congestion issues and can mitigate the impact of load growth and address certain market efficiency goals. However, siting generation in load pockets can itself be challenging, and there may be concerns about the environmental impact of conventional generation (depending on fuel type). Furthermore, the permanency of a generation MRA may be questionable – presumably if market conditions warrant, a rational investor in generation may choose to exit the market (unless that generator is under contract that compensates the resource out of market).[29]

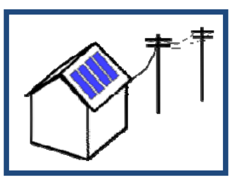
Conventional generation can provide many of the same services as transmission (see Figure 17). Conventional generation technologies can provide energy, ancillary services, and reduce system losses. They have a long lifespan, although as mentioned above, utility scale generation may be susceptible to market forces, which could lead to an early exit from the market. Depending on fuel type, utility-scale generation can operate on a continuous basis (utility-scale generation from intermittent resources such as wind and solar photovoltaic would not be able to provide service on a continuous basis, which results in a lower score relative to transmission). Utility-scale generation projects are generally implemented at the transmission level and are most impactful at the regional and local level.

Figure 17. Services Provided by Utility-scale Generation

[29] In which case, that generator would not be a "market-based resource alternative"

		Transmission	Utility-scale Generation
What	Energy	●	●
	Capacity	●	●
	Ancillary Services	●	●
	Reduce system losses	●	○
When	Long lifespan	●	◕
	Continuous basis	●	◑
Where	Regional	●	●
	Local	●	●
	Micro	●	○
How	System/Wholesale	●	●
	Customer/Retail	○	○

● Provided ○ Not provided



1.3.4 Distributed Generation

Distributed generation ("DG") systems are small generation systems located at a customer site.[30] Distributed generation at non-industrial customer sites has been a growing trend in recent years. The two reasons electricity systems have tended to be centralized and integrated are because (1) there have traditionally been substantial economies of scale in power plant development; and (2) integrated systems allow for diversification of load. The most important change that has occurred in some regions of the US in the electric industry over the past decades – deregulation and vertical unbundling –has given customers more choices in terms of their energy providers and supply options. The technological evolution has led to the development of various forms of on-site distributed

[30] The size (MW) threshold and other defining characteristics of distributed generation systems can vary by region. For example, in ERCOT, distributed generation systems are defined as systems of 10 MW of less located at a customer's point of delivery, and connected at a voltage less than or equal to 60 kV. *See:* ERCOT. "Distributed Generation Resources." <http://www.ercot.com/services/rq/re/dgresource>

generation. To date in the U.S., distributed generation has taken the form of on-site renewable energy systems such as solar photovoltaic ("PV") systems (accounting for 95% of total installed distributed generation systems as shown in Figure 18) and small wind turbines.[31] Solar PV systems have been a popular choice for distributed generation for several reasons. Their renewable characteristics make them enticing to customers (unlike fuel cells, which commonly use natural gas), and their relatively unobtrusive and small footprint makes them a good choice for customers in urban and suburban areas (unlike wind turbines, which face safety and obstruction issues in more densely populated areas). However, the intermittent nature of solar photovoltaic presents a challenge for system planners and operators who must take into account the intermittency and attendant dispatch uncertainty for these distributed resources.

Net metering is a service that allows customers deploying distributed generation to make sales back to the grid when the customer generates more power than they can consume themselves or reduce their consumption by "netting" their demand and generation behind the meter. The word "net" refers to the difference between electricity flowing from and into the distribution system. Utilities are required by the Energy Policy Act of 2005 to provide net metering programs. Currently, 43 states have net metering policies in place, and an additional three states have voluntary utility programs.[32] However, a challenge with net metering is that the rules vary significantly across jurisdictions with respect to factors such as how long customers can keep their banked credits, how much the credits are worth, whether credit values vary across time periods, etc. Although the penetration of distributed generation systems (as represented by installed net metering capacity) remains limited, it has been increasing (see Figure 18).

Building additional distributed generation facilities in a congested area can be an efficient way to alleviate the concerns of local load growth and therefore delay the need for new transmission investment. As an MRA, distributed generation has the potential to both reduce load (energy that the customer would otherwise purchase from the utility is now supplied on-site), and, as the penetration increases, can also serve as an additional generation source on the grid (excess energy generated at the customer site can be sold back into the grid).

Figure 18. Installed Distributed Generation Capacity in the U.S.

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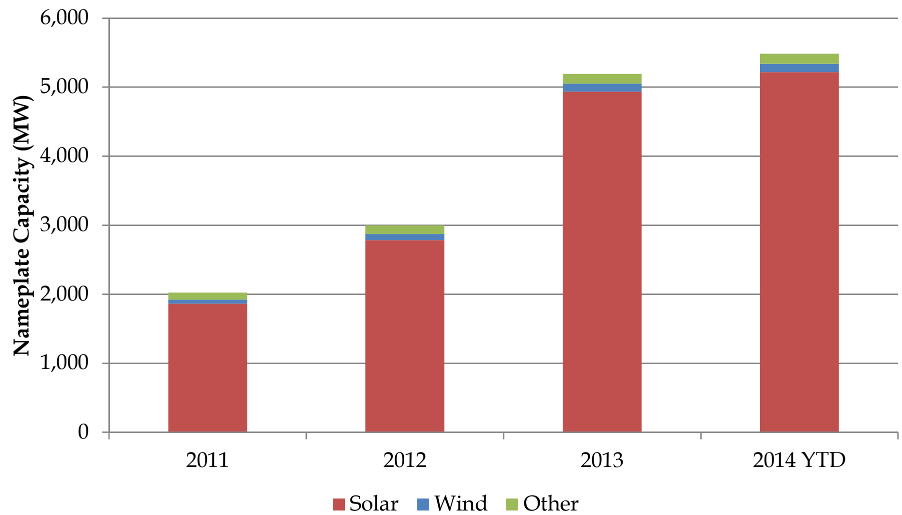
31 EIA. *Distributed Generation System Characteristics and Costs in the Buildings Sector.* August 2013.

32 Idaho, South Carolina, and Texas have voluntary utility programs. Alabama, Mississippi, South Dakota, and Tennessee are the only states that do not have net metering programs in place. *See:* DSIRE. *Net Metering.* Accessed May 22, 2014. <http://www.dsireusa.org/solar/solarpolicyguide/?id=17>



Source: EIA Form 826

There are technical challenges that come along with integrating DG resources into the grid. At low penetration levels, DG resources reduce load at the interconnecting substation. However, as penetration levels increase, the generation from DG resources can exceed load at the substation level, which results in unusual flow patterns as power flows from the substation to the grid. Typically, the existing distribution infrastructure was designed for a uni-directional power flow. Although bi-directional flow is possible, it requires incremental investments in equipment and changes in operating procedures. Therefore, additional steps need to be taken to ensure that DG resources do not adversely impact reliability and safety.[33] Furthermore, many distributed generation resources rely on intermittent fuel resources, such as wind and solar. The variability in production of solar and wind powered DG resources adds another layer of complexity to integrating large amounts of DG into the system.

Distributed Generation in Germany

Germany is often considered the leader in distributed (solar) generation, with nearly 36 GW of solar power installed on the system. The development of solar systems has been incentivized by the Renewable Energy Act of 2000, which established subsidizes for distributed generation.

The German experience has highlighted some of the challenges of such large amounts of renewable generation. The large amounts of intermittent resources have given rise to reliability problems on the grid, while market price signals have resulted in the shutdown of resources that are capable of rapidly balancing supply and demand.

See: Harvard Business Law Review. *The Challenge of Distributed Generation.* 2013; Fraunhofer Institute for Solar Energy Systems.

[33] For example, reverse flows can result in high-voltage swings and increase stress on circuit breakers. *See:* MIT. *Study on the Future of the Electric Grid.* 2011. Distributed generation also introduces risk and uncertainty into utility switching and tagging procedures during maintenance or restoration.

In addition to various technical issues, there are also some market issues that surround DG. As the installed net metering capacity has increased over the past years, various issues have been raised related to net metering, including the issue of unintentional subsidies, among others (see text box to the right). In effect, net metering rules often subsidize distributed generation, while utilities lack adequate incentives to make the investments that are necessary to accommodate distributed generation on the grid.

When considering the services provided by distributed generation, we consider the services that distributed generation from intermittent resources can provide, since, as noted above, nearly all of the distributed generation in the U.S. comes from solar and wind resources.

Externalities associated with DG

Installation subsidies: Utilities often cannot recover installations costs, only the cost of the actual meter, for net metering customers

Purchased power subsidies: Utilities typically purchase excess power at the utility's retail power rate (i.e., above wholesale market prices). Ultimately, non-net metering customers bear this cost.

Distribution cost subsidies: distribution costs (which are incurred regardless of customer usage) are typically recovered through consumption-dependent charges. Net metering customers still require these distribution services, but pay significantly less as their consumption is reduced.

DG resources can provide some but not all of the same services that transmission can provide (see Figure 19). Distributed generation can provide energy, capacity, ancillary services, and can reduce system losses. However, given the variable nature of their supply, they are only partially able to provide these services (but rank higher than load reducing resources such as energy efficiency as they are able to actively supply power and serve load). Distributed generation resources have a long lifespan, but given their intermittent nature are not able to provide services on a continuous basis. Distributed generation occurs at the customer level, and is most impactful at the micro or local levels.

Figure 19. Services Provided by Distributed Generation

		Transmission	Distributed Generation
What	Energy	●	◕
	Capacity	●	◕
	Ancillary Services	●	◕
	Reduce system losses	●	◔
When	Long lifespan	●	●
	Continuous basis	●	○
Where	Regional	●	○
	Local	●	●
	Micro	●	●
How	System/Wholesale	●	○
	Customer/Retail	○	●

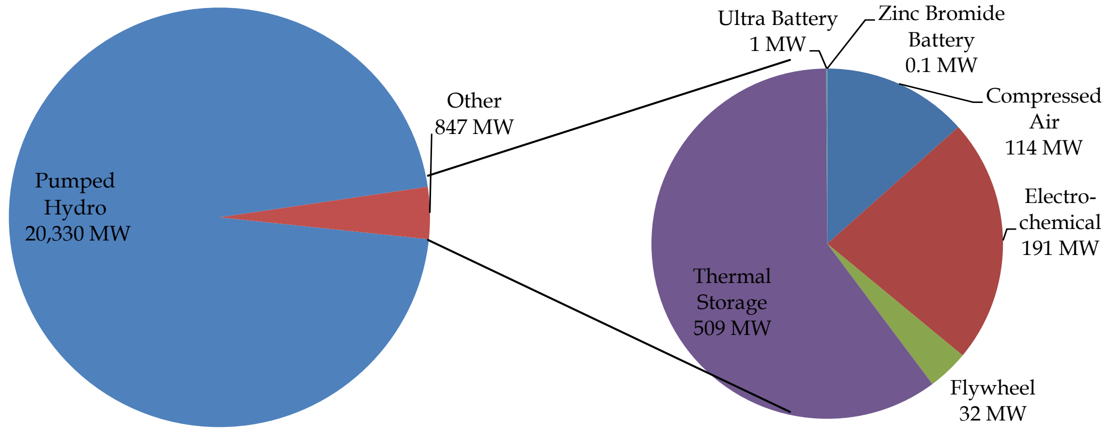
● Provided ○ Not provided

1.3.5 Energy Storage

Energy storage technologies allow electricity generated at one time to be used at another time. In effect, energy storage is a way of matching variable supply with variable demand by shifting energy across time. Energy storage can also be a useful redundancy option in areas with limited transmission capacity or volatile supply/demand profiles.

Currently, over 21 GW of energy storage capacity is operational in the U.S., 96% of which is pumped hydro storage capacity (see Figure 20). Pumped storage is a mature technology that has been in use for decades. Newer energy storage technologies, such as flywheels and batteries, have a limited penetration. Although these technologies are in some ways more flexible than pumped hydro storage (which is geographically constrained, as it can only be located in areas with sufficient hydro assets), for the most part they are not yet cost competitive and cannot solely rely on market revenues.

Figure 20. Energy Storage Installed Capacity



Source: DOE Global Energy Storage Database. Accessed May 20, 2014.
<http://www.energystorageexchange.org/>

As an MRA, energy storage offers several benefits to system planners. Energy storage can be used to supply energy during peak periods; to provide ancillary services to regulate grid frequency; and, energy storage facilitates an increased load capacity for renewable resources on the grid. This last benefit is especially important as state policies, such as RPS, have mandated an increase in renewable generation. In order to meet these goals, it is likely that a certain amount of energy storage will need to come online to support grid operations in light of large amounts of variable resources on the system.

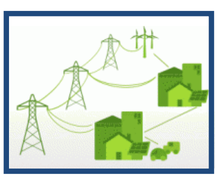
However, there are also a number of challenges that need to be considered when evaluating energy storage's potential as an MRA. First, many energy storage technologies are not cost competitive, which prevents wide-spread deployment. Second, market rules will need to be changed in order to develop a uniform process for evaluating and reporting the performance of existing storage systems. This is important especially in gaining a better understanding of the useful life of certain technologies, such as batteries. Finally, with the exception of pumped hydro storage, energy storage technologies have a limited commercial penetration to date. As a result, system operators have limited experience working with operational energy storage resources, which makes it challenging to develop a commercial, utility-scale process for integrating energy storage resources into system planning.

Energy storage resources are able to provide many of the same services as transmission, but do not have the same geographic reach (see Figure 21). Energy storage can shift energy across time, and thereby provide capacity and ancillary services. In some cases (but on a more localized basis), they can also reduce system losses. It also has a long lifespan and can operate on a continuous basis. While energy storage typically occurs at the system or wholesale market level, it is most impactful at the micro and local level. However, the biggest challenge with regard to energy storage resources is that, with the exception of pumped hydro storage, the technologies have not been widely deployed to date on a commercial scale, and are generally not yet cost competitive.

Figure 21. Services Provided by Energy Storage

		Transmission	Energy Storage
What	Energy	●	●
	Capacity	●	◕
	Ancillary Services	●	●
	Reduce system losses	●	◔
When	Long lifespan	●	●
	"24/7" basis	●	●
Where	Regional	●	◔
	Local	●	●
	Micro	●	●
How	System/Wholesale	●	●
	Customer/Retail	○	○

● Provided ○ Not provided



1.3.6 Smart Grid

MRAs can also take the form of improvements to transmission and distribution system capability through the deployment of performance devices, which may alleviate congestion through better control over the transmission grid and flows, and/or permit the more efficient use of supply-side options, such as generation. For example, transmission devices that reduce transmission and distribution losses are effectively equivalent to more energy from a generation facility. In addition to infrastructure components that work to reduce losses, other technologies have been (and continue to be) developed to improve system operations. Such devices are often referred to in the context of "smart grid" equipment. The term "smart grid" is effectively used in the industry to describe a suite of technologies that enables a more efficient use of the electric power grid through computer-based remote control and automation. To put this in context, the U.S. Department of Energy ("DOE") has stated that "if the grid were just 5 percent more efficient, the energy savings would equate to permanently eliminating the fuel and greenhouse gas emissions from 53 million cars."[34] When considering smart grid technologies, it is important to distinguish between smart grid applications for the transmission system and those for the distribution system.

Smart Grid – Transmission

Smart grid technologies for the transmission system improve efficiency by allowing system operators to remotely control and monitor the transmission lines in real-time. For example, phasor measurement units allow system operators to monitor transmission lines and allow for the early detection of fault. In another example, distributing temperature sensing technology provides system operators with real-time information on transmission lines, enabling maximum utilization of the lines while maintaining safety and reliability. Many of these smart grid technologies are currently deployed by transmission providers, and are more properly considered as transmission enhancements rather than MRAs. Therefore, we have not classified transmission smart grid as a form of an MRA.

Smart Grid - Distribution

The distribution system is the conduit between the higher voltage transmission system and the end-use customer. Smart grid applications for the distribution system are often two-way communication technologies that allow utilities and system operators to detect and react to local changes. Smart grid distribution technologies, an MRA in their own right, often go hand in hand with other MRAs. In fact, without smart grid technologies, certain MRAs would not be feasible. For example, demand response programs rely on advanced metering infrastructure ("AMI" or "smart meters"). These smart meters can control and manage the flow of electricity to and from the customer site, and communicate information on the customer's energy usage and patterns to the utility.[35] Specialized smart meters are also required for distributed generation to monitor the amounts of power that a customer receives from and delivers to the grid. One of the challenges in using these types of distribution level smart grid applications is customer acceptance. Many customers have privacy concerns related to smart meters, and most smart meter programs have an "opt out" clause that allows customers to decide whether or not they want a smart meter installed at their residence. The more customers that opt out, the less system planners and operators can rely on other MRAs that require these meters to successfully particpate in the market (i.e., demand response).

Smart grid distribution technologies provide many of the same services as transmission, but have a more limited geographical range (see Figure 22). Smart grid distribution technologies can provide energy and reduce system losses. Smart grid distribution technologies cannot provide capacity, and can provide only some ancillary services relative to those provided by

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[34] US Department of Energy. *The Smart Grid: An Introduction*. September 2008.

[35] IEEE. "Smart Grid Conceptual Model." <http://smartgrid.ieee.org/ieee-smart-grid/smart-grid-conceptual-model>

transmission. They have a long lifespan, and can operate on a continuous basis. As distribution technologies, they are generally implemented at the customer level, and have a very localized impact, with limited ability to impact the regional level.

Figure 22. Services Provided by Smart Grid – Distribution

		Transmission	Smart Grid - Distribution
What	Energy	●	●
	Capacity	●	○
	Ancillary Services	●	◑
	Reduce system losses	●	◔
When	Long lifespan	●	●
	Continuous basis	●	●
Where	Regional	●	○
	Local	●	●
	Micro	●	●
How	System/Wholesale	●	○
	Customer/Retail	○	●

● Provided ○ Not provided

1.4 Key Takeaways

During the planning process, system planners will need to evaluate the services transmission and MRAs can provide, as well as the benefits they provide. In our descriptions of the MRAs above, we discussed the services provided by transmission and MRAs. Figure 23 below combines the individual MRA summaries into a comparative table. This table provides an indication of the ability of each type of MRA to provide the services that are fully provided by transmission, based on what we know today about MRAs and current technology. While bearing in mind that the chart captures the relative capabilities of MRAs and transmission only for the basic services, we find that individual MRAs (based on current technology) are generally not capable of providing all of the same services that transmission provides for the same tenure and geographical dimension.

Figure 23. Services provided by MRAs relative to transmission

		Transmission	Energy Efficiency	Demand Response	Utility-scale Generation	Distributed Generation	Energy Storage	Smart Grid - Distribution
What	Energy	●	◑	◑	●	◕	●	●
	Capacity	●	◑	◑	●	◑	◕	○
	Ancillary Services	●	○	◑	●	◕	●	◑
	Reduce system losses	●	◑	◑	○	◔	◔	◔
When	Long lifespan	●	◕	○	◕	●	●	●
	Continuous basis	●	◕	○	◑	○	●	●
Where	Regional	●	◑	◑	●	◔	◔	○
	Local	●	●	●	●	●	●	●
	Micro	●	●	●	○	●	●	●
How	System/Wholesale	●	○	○	●	○	●	○
	Customer/Retail	○	●	●	○	●	○	●
	TOTAL	●	◑	◔	◕	◑	◕	◑

● Provided ○ Not provided

In order to allow for quicker comparison, we have provided a "total score" for transmission and MRAs in the final row of the table. This "total score" gives equal weight to all categories listed. As we will discuss more in Chapter 4, it may be appropriate for more weight to be given to certain categories than others during the system planning process depending on the needs identified by the system planner. However, this ranking provides a few key takeaways: first, an MRA generally only is able to provide partial suite of services that transmission provides; second, even among MRAs there is varying ability to provide services. For example, MRAs such as utility scale generation and smart grid (distribution) can provide a wider variety of services than other MRAs such as demand response and energy efficiency, even though utility-scale generation and smart grid (distribution) are not able to provide the full set of services provided by transmission.

Understanding the dimensions of the services provided by MRAs ties into the consideration of the potential benefits of MRAs vis-à-vis the many benefits of transmission typically recognized and considered during the system planning process. Our description of MRAs has highlighted some of the challenges or limitations of each MRA in providing the full suite of benefits and services provided by transmission. Some of these limitations are "structural" or inherent to the MRA – for example, demand response by definition will only provide services on a periodic basis rather than a continuous basis. Other challenges may be external, a result of policy or public opinion – for example, privacy concerns about smart meters limit their penetration, which in turn limits the amount of benefits that can be captured from smart meter deployment. Figure 24 below provides a summary of the key challenges associated with each MRA that prevent them from providing the full range of benefits and services.

Figure 24. Challenges associated with MRAs

MRA	Challenges
Energy Efficiency	• Difficult to accurately forecast • May lead to unintended increase in demand (rather than decrease) • Shifts in consumption patterns may limit efficacy • Market-procured EE may leave market in response to market signals • Limited regional impact (best at micro or local levels)
Demand Response	• Operational and payment issues related to treatment of DR in wholesale markets • Variability in performance (customers may not offer into market if they find that the cost of doing so outweighs the perceived benefits) • Limited regional impact (best at micro or local levels) • Short lifespan
Utility-scale Generation	• Siting generation in areas where it is most needed (i.e., load pockets) can be challenging • Environmental concerns (for conventional generation) • Operational challenges for renewable generation (i.e., intermittency) • May exit market in response to market conditions (unless under contract)
Distributed Generation	• Technical challenges in managing bi-directional flow • Inconsistent net metering policies across jurisdictions • Negative externalities in the form of subsidies • Operational challenges due to intermittent nature • At high penetration levels, DG can send market signals causing other resources to exit the market, which then undermines system reliability
Energy Storage	• Most technologies are not cost competitive • Inconsistent processes for evaluating and reporting resource performance • Limited penetration (with the exception of pumped hydro, most technologies are not yet well developed) • Permanency issues – market-procured resources may leave the market
Smart Grid - Distribution	• Negative public perception (privacy concerns) limit ability to provide services and capture benefits • Limited regional impact • Limited ability to provide capacity and ancillary services

Our discussion in Chapter 4 will come back to the consideration of the dimensions of service and the qualities of MRAs relative to more in-depth consideration of benefits in order to recommend analytical tools and techniques for evaluating the benefits offered by transmission and MRAs. However, there are a few key takeaways to bear in mind as we develop the proposed cost-benefit framework and analytical toolkit:

- ***Individual MRAs typically provide a partial suite of the services that transmission provides.*** Furthermore, there is considerable variety among MRAs in their ability to provide services. In other words, no single MRA is a workable substitute for transmission. However, MRAs (either individually or in combination) can serve as complements to transmission, and vice versa.

- ***Permanence is a considerable challenge for MRAs.*** When compared to transmission almost every MRA is less permanent. This issue of permanency is significant for system planners and operators, as well as for customers who ultimately should benefit from any selected transmission or MRA project. Given the long time horizon of system planning, system planners (and operators) need to be reasonably certain that they can rely on the solutions they put in place. Indeed, as we will see in Chapter 3, the issue of permanence has led system planners to reject MRAs as potential solutions in some instances.

- ***MRAs can have negative externalities which can erode or even exceed their potential benefits.*** Furthermore, the magnitude of these externalities is uncertain, and at times can be unexpected since experience with certain MRAs is limited to very low penetration levels. For example, the impact of externalities associated with distributed generation increases with the penetration level. At higher penetration levels, distributed generation can impact market prices, which causes other resources to exit the market. Without these resources, the system may not be able to balance the intermittent nature of the distributed generation resources (most commonly wind and solar), and ultimately system reliability – security and resource adequacy - is undermined.

- ***System planning involves optimizing a portfolio of infrastructure elements.*** Therefore understanding the interaction between transmission and MRAs is important. For example, transmission and MRAs may complement each other, a relationship that could provide additional benefits to the system.

Chapter 2: Federal and Regional Policies surrounding Market Resource Alternatives

FERC highlighted the importance of MRAs in 2007 with the issuance of Order 890. Although Order 890 does not have explicit requirements related to MRAs, in its decision FERC noted that "transmission planning is a critical function…because it is the means by which customers consider and access new sources of energy and have an opportunity to explore the feasibility of non-transmission alternatives."[36] With Order 890, FERC laid the foundation for regional transmission planning processes that considered economics as well as reliability needs. In addition, Order 890 suggested (but did not yet require) that consideration of MRAs become an integral part of system planning.

Several years later FERC issued Order 1000 to further refine and improve transmission planning. FERC Order 1000, issued in July 2011, consists of three areas of reform:

- **Transmission planning requirements:** FERC Order 1000 requires public utility transmission owners ("TOs") to participate in the regional (and inter-regional) planning process. The regional planning process must satisfy the principles outlined in Order 890 (including economic studies), and should result in a regional transmission plan. Furthermore, local and regional transmission planning processes must explicitly incorporate the analysis of transmission needs that are driven by public policy requirements both at the state and federal level (for example, energy efficiency and RPS).[37] Order 1000 also requires that MRAs be treated comparably with transmission in the regional transmission planning process to meet the needs of the region more efficiently and in a more cost-effective manner.[38] Stakeholders must also be given the opportunity to participate in identifying and evaluating the potential solutions to regional needs, including transmission and non-transmission solutions.
- **Cost allocation requirements:** On the cost-allocation front, FERC Order 1000 requires the development of regional cost allocation methods for new transmission facilities selected as part of the regional transmission plan. The regional cost allocation method must allocate costs "in a manner that is at least roughly commensurate with the benefits received by those who will pay those costs. Costs may not be involuntarily allocated to entities that do not receive benefits."[39] The Order does not require a "one size fits all" cost allocation methodology, but all methodologies must adhere to the same principles, including the allocation of costs only to those who benefit from the new transmission infrastructure.

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[36] *Ibid* at 3.

[37] FERC Order No. 1000 at P 6.

[38] *Ibid* at P 537.

[39] *Ibid* at P 15.

- **Non-incumbent developer requirements:** Order 1000 seeks to encourage competition in the regional planning processes in an effort to achieve efficient and cost-effective transmission development. With that goal in mind, Order 1000 requires "that any non-incumbent developer of a transmission facility selected in the regional transmission plan have an opportunity comparable to that of an incumbent transmission developer to allocate the cost of such transmission facility through a regional cost allocation method or methods."[40] In addition, Order 1000 removes any federal right of first refusal from FERC-approved tariffs and agreements with respect to new transmission facilities selected in a regional transmission plan.

To date, TOs have not incorporated MRAs into system planning processes in a comprehensive and consistent manner. FERC has recognized the lack of systematic review of MRAs in transmission planning, and has attempted to address that failing with Order 1000. However, Order 1000 remains fairly limited in scope with regard to MRAs.[41] For example, although Order 1000 requires consideration of MRAs in regional transmission planning, it does not establish any requirements as to which MRAs should be considered or what the appropriate metrics for evaluating MRAs against transmission solutions would be. Furthermore, Order 1000 does not address the issue of cost recovery for MRAs. While FERC stated that "the issue of cost recovery for non-transmission alternatives is beyond the scope of the transmission cost allocation reforms we are adopting here, which are limited to allocating the costs of new transmission facilities," it did note that "in appropriate circumstances, alternative technologies may be eligible for treatment as transmission for ratemaking purposes."[42]

2.1 Consideration of MRAs in Current ISO/RTO Planning Processes

With the adoption of FERC's Order 1000,[43] transmission providers have an obligation to consider feasible MRAs when evaluating proposed transmission projects. Every RTO in the U.S. has submitted compliance filings with FERC in which the RTOs state that they are in compliance with the requirements of FERC Order 1000, including the requirement to consider MRAs and transmission on a comparable basis. While FERC has accepted some of the compliance filings in select markets, FERC required that other markets must further refine and/or enhance its planning process before FERC will accept the compliance filing. Based on our review of current transmission planning processes in ISO/RTOs across the U.S., MRAs

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[40] *Ibid* at P 175.

[41] FERC Order 1000 refers to MRAs as "non-transmission alternatives", or "NTAs".

[42] *Ibid* at P 537.

[43] Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* FERC Stats. & Regs. ¶ 31,323, 76 Fed. Reg. 49,842 (2011) [hereinafter Order No. 1000], *order on reh'g,* Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g,* Order No. 1000-B. 141 FERC ¶ 61,044 (2012), *aff'd sub nom. South Carolina Pub. Serv. Auth. v. FERC*, --- F.3d ---, 2014 WL 3973116 (D.C. Cir. Aug. 15, 2014).

appear to generally be considered in the transmission planning process, although the timing of this consideration and the extent to which MRAs are evaluated varies. In the following sections, we describe how MRAs are currently considered in each ISO/RTO's transmission planning process and provide a summary of each RTO's compliance with Order 1000 with respect to MRAs. Figure 25 provides a brief overview of how MRAs are currently considered in each ISO/RTO.[44]

Figure 25. MRAs and Current RTO Planning Processes

RTO	Planning Process	MRA Approach Approved by FERC?	Example of MRA Analysis
CAISO	Transmission Planning Process	Approved	MRAs considered in the 2013-2014 planning cycle for the LA Basin and San Diego (no decision to date)
ERCOT*	N/A	N/A	MRA analysis considered in the Houston Import Project (transmission selected)
ISO-NE	Regional System Planning	Approved	ISO-NE conducted pilot studies primarily for demonstration purposes; MRAs also considered at state level regulatory processes (transmission selected)
MISO	MISO Transmission Expansion Planning	Approved	No MRA analysis conducted to date
NYISO	Comprehensive System Planning Process	Approved	Transmission and MRAs have been considered by the NY PSC in the context of system needs that have arisen as a result of generation retirements
PJM	Regional Transmission Expansion Plan	Approved	PJM considers MRAs based on the resources committed to the RPM
SPP	Integrated Transmission Planning	Approved	No MRA analysis conducted to date

** ERCOT is not subject to FERC jurisdiction, and therefore is not required to comply with Order 1000*

2.1.1 California Independent System Operator

One of the major responsibilities of CAISO is to develop the transmission infrastructure planning of the CAISO-controlled grid. To fulfill this task, CAISO conducts an annual transmission planning process in consultation with California utilities and state agencies, including the California Public Utilities Commission ("CPUC") and the California Local Regulatory Authorities ("LRA").[45] The process culminates in a CAISO Board-approved

[44] We have included ERCOT for completeness, although ERCOT is not under FERC jurisdiction and therefore does not need to comply with FERC's Order 1000.

[45] An LRA is "the state or local governmental authority, or the board of directors of an electric cooperative, responsible for the regulation or oversight of a utility." *See:* CAISO Glossary.

comprehensive transmission plan. This plan identifies needed transmission additions and upgrades, and authorizes cost recovery through the CAISO transmission rates.

California state agencies have a long history of supporting non-conventional alternatives to transmission. In fact, CAISO considered MRAs on a comparable basis long before Order 1000. California's support for various MRAs in context of system planning dates back to the Energy Action Plan adopted in 2003 (most recently updated in 2008) by the CPUC, California Energy Commission, and California Power Authority. The Energy Action Plan supports a "loading order" of preferred resources to meet California's increasing energy needs. Energy efficiency and demand response are first, followed by renewable sources and clean distributed generation. To the extent that these efforts are unable to satisfy increasing energy and capacity needs, the state supports clean and efficient fossil-fired generation.[46]The Energy Action Plan also recognized that "investment in conventional transmission infrastructure is crucial to helping the state meet its renewable energy goals."[47] Note that Energy Action Plan's support for MRAs does not build upon a solid economic analysis but is mostly driven by state policy preference. A comprehensive economic analysis should be performed to fully understand the net benefits of MRAs and transmission projects. Then the investment decision will result in an efficient market outcome.

In addition to the state's long history of supporting non-conventional alternatives to transmission, CAISO also has a longer history than other ISOs/RTOs of conducting comprehensive economic assessment of transmission. CAISO's Transmission Economic Assessment Methodology ("TEAM"), which has been in place since 2004, allows for a comprehensive evaluation of benefits of transmission, taking into account uncertainty. It is also considerate of the MRA and transmission interdependency, as it is based in part on the premise that the "economic value of a proposed transmission upgrade is directly dependent on the cost of resources that could be added or implemented in lieu of the upgrade." Specifically, TEAM implements enhancements to the traditional transmission evaluation framework by capturing explicitly "interaction between generation, demand-side management, and transmission investment decisions" and recognizing that a transmission expansion can impact the economics or profitability of new investment from the private investors' perspective. Thus, the TEAM methodology considers both the objectives of investors in resources (private profits) and the transmission planner (societal net-benefits)."[48] The use of preferred resources as non-conventional alternatives to transmission is an approach that was further developed in 2013

<http://www.caiso.com/pages/glossary.aspx?View={02340A1A-683C-4493-B284-8B949002D449}&FilterField1=Letter&FilterValue1=L>

46 State of California. "2008 Update: Energy Action Plan." February 2008. Available at: <http://www.energy.ca.gov/2008publications/CEC-100-2008-001/CEC-100-2008-001.PDF>

47 *Ibid.* p6.

48 CAISO. "Transmission Economics Assessment Methodology (TEAM)." June 2004. Available at: <http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology.pdf>

with CAISO's publication of a proposed methodology for considering non-conventional alternatives (MRAs).[49] Not surprisingly, FERC approved CAISO's compliance filing where it related to the treatment of MRAs.[50]

CAISO's Transmission Planning Process

The CAISO's annual comprehensive transmission plan is developed through the Transmission Planning Process ("TPP"), which involves three main phases. Phase 1 consists of establishing the assumptions and models that will be used in the planning studies, developing and finalizing the study plan, and developing a state-wide conceptual plan to serve as an input consideration for the comprehensive transmission plan. In addition, Phase 1 involves specifying the public policy mandates that CAISO will adopt as objectives for determining policy-driven projects in the current TPP cycle.[51]

During Phase 2 of the TPP, CAISO performs all the necessary technical studies to identify the needed transmission additions and upgrades. During Phase 2, CAISO, in conjunction with the CPUC, conducts a series of stakeholder meetings, and develops an annual comprehensive transmission plan. In addition, any transmission upgrades or additions that are deemed necessary to ensure system reliability can be submitted through the Request Window.[52]

MRAs are considered during Phase 2 of the planning process when CAISO commences the process of performing studies to identify transmission needs. The transmission needs are adapted from the assumptions and models used in the planning studies that have been established in Phase 1. Phase 2 culminates in the annual comprehensive transmission plan. Essentially, MRAs are identified and considered at the same time as conventional transmission projects.

Finally, Phase 3 of the TPP involves the competitive solicitation for prospective developers to build and own transmission elements in the economic- and policy-driven categories of the Board-approved plan.

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49 CAISO. "Consideration of alternatives to transmission or conventional generation to address local needs in transmission planning process." September 4, 2013. Available at: <http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014TransmissionPlanningProcess.pdf>

50 FERC rejected California State Water Project's suggestion that FERC require CAISO to take further action regarding the incorporation of non-transmission alternatives into the transmission planning process with respect to compensation issues.

51 CAISO. Section 1 of the *2012-2013 Transmission Planning Process Unified Planning Assumptions and Study Plan*. March 30, 2012.

52 CAISO. Section 4.4 of the *Business Practice Manual for the Transmission Planning Process*. Version 11.0. Last revised on April 24, 2013.

Categories of Transmission Projects

CAISO classifies proposed transmission projects along three categories: (i) reliability-driven, (ii) policy-driven, or (iii) economic-driven. The corresponding category analyses differ, as each is set against a specific objective and criteria; however, there is some integration of the categories to allow for a more comprehensive analysis. For example, the study of needs under these three categories is prepared sequentially, building upon the previous category. A policy-driven project may be either a new concept or an expansion of a previously identified reliability-driven project. Furthermore, in considering the best solution to address any given need, the benefits that may be provided in the other categories can also be taken into account. For example, additional reliability and economic benefits may drive the selection of a particular solution to a policy need.

Reliability-driven transmission upgrade projects are identified via reliability studies using the following criteria: need of the proposed transmission upgrade to meet NERC reliability and CAISO transmission planning standards, and WECC criteria. CAISO evaluates proposals under this category by reviewing technical viability, reliability, efficiency, and compliance with industry standards, and relative cost-effectiveness of the proposed transmission upgrade in comparison to alternatives.[53]

Public policy objectives are identified in Phase 1, and the policy-driven transmission projects are identified as either Category 1 (deemed as needed and recommended to the CAISO Board for approval), or Category 2 (will not be recommended to the CAISO Board for approval during the current cycle) using the criteria shown in Figure 27.

CAISO determines the economically-driven transmission elements performing economic planning studies as outlined below, evaluating whether the proposed transmission upgrade project relieves congestion; and, in particular, whether the proposed project provides capacity benefits, transmission loss savings, and production cost savings measured in line with TEAM principles.[54] CAISO also consider whether the proposed economic-driven project is the most cost effective way to mitigate the particular congestion problem.[55]

There are two steps under the economic planning study as shown in Figure 26 below. The first step is identifying the congestion in the transmission grid by using a production cost-based simulation of the system. The identified congestion is ranked by severity, which is expressed as congestion costs in dollars and congestion duration in hours.[56] Then, the CAISO identifies high priority areas of congestion (up to five) for further analysis. After performing the power system

[53] CAISO. Section 4.7 of the *Business Practice Manual for Transmission Planning Process*. April 24, 2013.

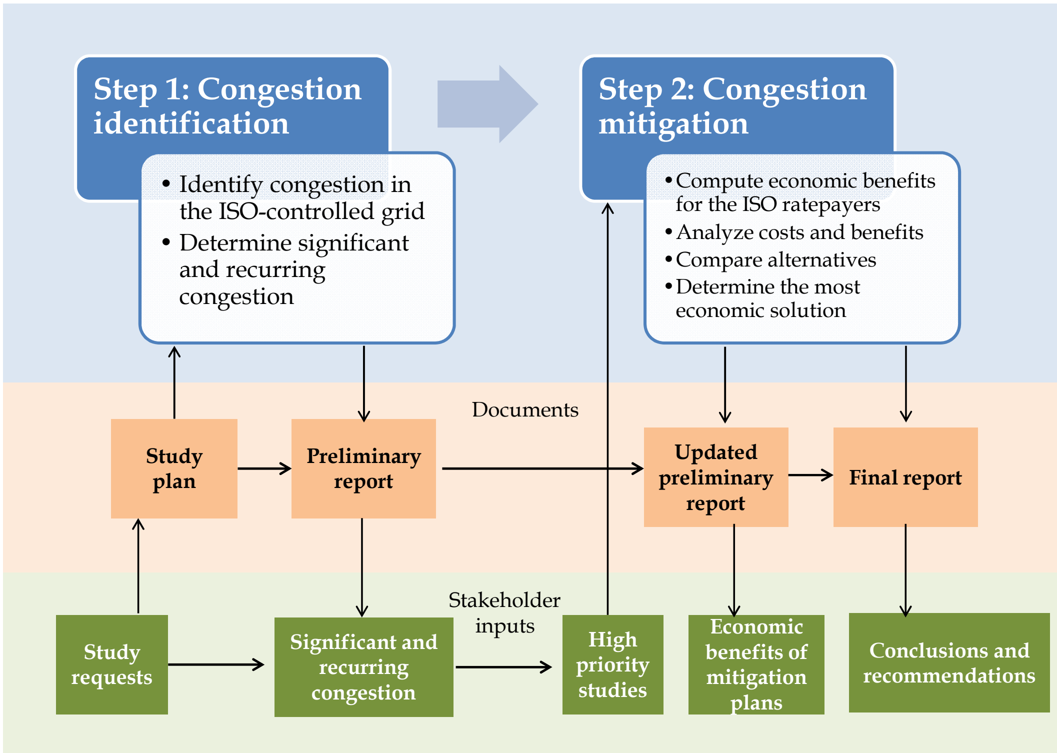
[54] The TEAM framework is discussed in Section 2.1.1

[55] CAISO. Section 4.9 of the *Business Practice Manual for Transmission Planning Process*. April 24, 2013.

[56] CAISO. *2012-2013 ISO Transmission Plan*. March 20, 2013. P. 18.

simulation, the second step in the economic planning study is the evaluation of the congestion mitigation plans for each of the "high-priority studies" or areas of concern.

Figure 26. Two steps of the Economic Planning Study at CAISO



Source: CAISO (Economic Planning Study of Grid Congestion – The Study Plan)

CAISO quantifies the economic benefits for each of the identified high-priority studies. A total cost-benefit analysis is performed to determine if the proposed network upgrades are cost-efficient. In order to justify a proposed network upgrade, the ISO ratepayer benefits must be greater than the costs of the network upgrade. Total benefit is defined as the accumulated annual benefits over the economic life of the proposed transmission project.[57] The annual benefits are discounted to the present value in the proposed operation year before the dollar value is accumulated to the total economic benefit.[58] The total benefits include production cost savings, capacity benefits, and other benefits that are quantifiable.

When there are multiple alternatives that could address identified congestion issues, the net benefits are compared with each other. In addition, for the proposed network upgrades that

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[57] CAISO assumes that the economic life of a new transmission facility is 50 years while the economic life of upgraded transmission facility is 40 years.

[58] CAISO. *2012-2013 ISO Transmission Plan*. March 20, 2013. P. 315.

have significant benefits, CAISO also performs comprehensive sensitivity analyses to account for planning uncertainties.

Figure 27. Metrics Considered in CAISO's Transmission Planning Process

Project Category	Metrics Considered
Reliability	✓ Technical viability ✓ Efficiency ✓ Product Cost Savings
Public Policy	✓ Production costs ✓ Value of MW/MWh to meet policy requirements ✓ Environmental impacts ✓ Reliability benefits ✓ Economic benefits ✓ Ability to allow new resources to access the grid
Economic	✓ Ability to relieve congestion ✓ Capacity benefits ✓ Transmission loss savings ✓ Product cost savings

Recent Developments

In the course of the 2012-2013 planning cycle, there was considerable additional industry emphasis placed on the potential for MRAs (in particular, energy efficiency and demand-side management programs) to meet resource adequacy needs that would otherwise necessitate transmission development. However, the industry interest in this aspect received limited response in the 2012-2013 planning cycle,[59] likely due to the fact that utilities were still waiting for CPUC authorization pertaining to certain energy storage and energy efficiency decisions. Finally, CPUC's decision on energy storage came out in October 2013,[60] long after the beginning of the 2012-13 TPP. This decision established a target of 1,325 MW of energy storage to be procured by Pacific Gas and Electric Company ("PGE"), Southern California Edison Company ("SCE"), and San Diego Gas & Electric Company ("SDGE") by 2020, with installations required no later than the end of 2024.

In the 2013-2014 transmission planning cycle, MRAs were considered for the LA Basin and San Diego areas. Because of the magnitude of the reliability needs in these areas, incremental transmission options were also studied to complement MRAs to reduce the need for

[59] CAISO. "2013-2014 Transmission Plan." March 25, 2014. Page 21. <http://www.caiso.com/Documents/Board-Approved2013-2014TransmissionPlan.pdf>

[60] CPUC. "*Decision adopting energy storage procurement framework and design program*." October 17, 2013.

conventional generation to fill the gap.[61] The reliability needs were driven largely by the closure of the San Onofre Nuclear Generating Station ("SONGS") in southern California, which represented ~16% of local supply. The closure raised supply concerns as well as concerns about voltage support.[62] The main focus of the effort was to evaluate available MRAs in the LA Basin and San Diego areas and identify the performance attributes of these alternatives that could effectively address the local reliability needs in these two priority areas as part of a basket of resources.[63] In general, these performance attributes cover three main characteristics: (1) ***response time*** – how quickly can the resource respond to an ISO dispatch; (2) ***duration*** – how long can the resource sustain its response; and (3) ***availability*** – how many times can the resource be called during a time period. As part of the evaluation process, CAISO assessed both preferred resources suggested by SCE for the LA Basin as well as energy storage proposals offered. As of July 2014, no decision had been made.

Once the MRAs are part of the CAISO approved transmission plan, the information obtained by the CAISO during the TTP will inform any CPUC decisions on authorizing procurement of additional preferred resources in these areas. Once CPUC has approved procurements for MRAs along with other procurement needs of the utilities, California utilities then go out and solicit for them. Given that California utilities are allowed to offer long-term contracts, this means somewhat less uncertainty in whether the MRAs will materialize in the market.

In addition to MRAs being considered in the transmission planning process, the CPUC is required to consider MRAs in the transmission permitting process before issuing certificates of pubic convenience and necessity ("CPCN"). More specifically, California Public Utilities Code Section 1002.3 requires that the CPUC consider MRAs before issuing a CPCN for proposed transmission lines. Specifically, Section 1002.3 states that "in considering an application for a certificate for an electric transmission facility pursuant to Section 1001, the commission shall consider cost-effective alternatives to transmission facilities that meet the need for an efficient, reliable, and affordable supply of electricity, including, but not limited to, demand-side alternatives such as targeted energy efficiency, ultraclean distributed generation."[64] CPUC also incorporates MRAs (including energy efficiency, demand response, and distributed generation) when performing the economic modeling. In 2008, CPUC used this approach in its decision granting SDGE a CPCN for the Sunrise Powerlink Transmission Project.

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[61] CAISO. *Consideration of Alternatives to Transmission or Conventional Generation to Address Local Needs in the Transmission Planning Process.* September 4, 2013. <http://www.caiso.com/documents/paper-non-conventionalalternatives-2013-2014transmissionplanningprocess.pdf>

[62] CPUC. *Preliminary Reliability Plan for LA Basin and San Diego.* August 30, 2013. <http://www.energy.ca.gov/2013_energypolicy/documents/2013-09-09_workshop/2013-08-30_prelim_plan.pdf>

[63] CPUC. "*Decision adopting energy storage procurement framework and design program*." October 17, 2013.

[64] California Public Utilities Code Section 1002.3. Law and Legal Research. March 17th, 2014. <http://law.onecle.com/california/utilities/1002.3.html>

The effort of supporting non-conventional alternatives to transmission continues in California. Two pieces of legislation currently being considered would further reinforce this priority. First, Assembly Bill 177, which is currently being discussed in the California Legislature, would direct utilities to procure all cost-effective preferred resources, irrespective of current legislative or regulatory targets.[65]

Second, Assembly Bill 327, last amended in September 2013, would require: "no later than July 1, 2015, each electrical corporation to submit to the PUC a distribution resources plan proposal identifying optimal locations for the deployment of preferred resources, as follows:

1) Evaluate locational benefits and costs of preferred resources located on the distribution system, as specified;

2) Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective preferred resources that satisfy distribution planning objectives;

3) Propose cost-effective methods of effectively coordinating existing PUC-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of preferred resources;

4) Identify any additional utility spending necessary to integrate cost-effective preferred resources into distribution planning consistent with the goal of yielding net benefits to ratepayers."[66]

2.1.2 Electric Reliability Council of Texas

ERCOT's Transmission Planning Process

ERCOT is not under FERC jurisdiction and therefore is not subject to compliance with FERC Order 1000. Nevertheless, ERCOT undertakes a rigorous transmission planning process in conjunction with the transmission owners (known as Transmission Service Providers ("TSPs")), which includes a mandatory consideration of MRAs. Any transmission project that is formally proposed for the consideration of ERCOT's Regional Planning Group ("RPG") is expected to provide a description of feasible alternatives considered.[67] In other words, if a TSP is proposing a transmission project for consideration, it must also identify other feasible alternatives for consideration. Then, both ERCOT and TSPs are responsible for evaluating the need for transmission system improvements and evaluating the relative value of alternatives. When transmission projects are proposed by TSPs (or other parties) for ERCOT review, the proposers

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[65] Assembly Bill 177. <http://www.leginfo.ca.gov/pub/13-14/bill/asm/ab_0301-0350/ab_327_cfa_20130904_154102_sen_floor.html>

[66] Assembly Bill 327. <http://www.leginfo.ca.gov/pub/13-14/bill/asm/ab_0301-0350/ab_327_cfa_20130904_154102_sen_floor.html>

[67] ERCOT Planning Guide. Section 3.1.2.1(a).

are asked to provide a list of feasible alternatives considered, and any supporting analysis related to those alternatives.[68] When ERCOT, through the RPG, evaluates the proposed transmission projects, "several alternatives will be identified to meet the reliability criteria or other performance improvement objectives that the proposed project is designed to meet."[69] The alternative with the lowest expected cost over the project life is typically recommended

MRAs in ERCOT generally include: (1) building new generation facilities in a congested area; (2) initiatives to reduce loads during periods of transmission congestion (e.g., dispatchable load control); and (3) generating unit re-dispatch.[70] MRAs such as energy-efficiency and demand response are considered as part of the demand forecasts.

Transmission projects and MRAs are typically screened both through a technical evaluation and a cost analysis. For the technical evaluation, ERCOT typically performs a contingency analysis to identify options that mitigate the identified reliability concerns under N-1 conditions. Then, as a second step, ERCOT may study the G-1+N-1 conditions (generator unit outage plus a contingency). For the selected options, ERCOT conducts a power transfer analysis to evaluate thermal and voltage stability limits. ERCOT may also run several scenarios when evaluating options to determine the impact of potential retirements and to assess the transmission efficiency of each option in terms of system loss reduction.

Categories of Transmission Projects

In ERCOT, transmission projects are categorized either as reliability-driven projects or economic-driven projects. Reliability-driven projects are projects that are necessary to resolve a reliability issue (that is, without these projects, the issue would not be resolved). Economic projects are those projects that, while not necessary to resolve the reliability issue (that is, the issue could be resolved by some other project), allow reliability criteria to be met at a lower cost.

Both reliability and economic projects are subject to technical analysis. However, the cost analysis depends on the type of transmission project. For reliability-driven projects, the costs of the alternatives are generally compared based only on the relative capital costs. For economic projects, the benefits are assessed based on the net societal benefit that is expected to accrue from the project. The societal benefit is determined by comparing the revenue requirement of the capital cost of the project to the expected savings in system production costs resulting from the project (all analysis is performed over the project life). Indirect benefits and costs are also considered, as appropriate.

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[68] *Ibid.*

[69] ERCOT Planning Guide. Section 3.1.3(1)

[70] Discussions with ERCOT. Unit re-dispatch is the only alternative explicitly mentioned in ERCOT's Planning Guide.

Figure 28. Metrics Considered in ERCOT's Transmission Planning Process

Project Category	Metrics Considered
Reliability	✓ Technical viability ✓ Capital costs
Economic	✓ Technical viability ✓ Production cost savings ✓ Indirect benefits and costs (as appropriate)

Recent Developments

ERCOT's recent analysis of the Houston Import Project is an example of ERCOT's high-level approach to MRAs. The Houston Import Project is a reliability-driven transmission project and new generation and/or demand response were considered by the RPG in its review of the options proposed for the Houston Import Project (results were published in February 2014). Specifically, load was scaled down to mimic new generation or demand response coming on line. Given that the Houston Import Project is a reliability project, alternatives were evaluated primarily on their ability to meet the identified reliability needs under various scenarios. The cost/economic analysis was a secondary consideration and a full analysis of the net societal benefits was not conducted. In the end, ERCOT decided to pursue a conventional transmission project, namely a new 122 mile, 345 kV transmission line from ERCOT's North zone to the Houston zone. Upgrades are expected to be made at several substations to accommodate the new line, and an existing 345 kV line will also be upgraded.[71] ERCOT concluded that, in principle, the addition of 1,800 MW of generation and/or demand response would defer the need for the project by one year, until 2019. Nonetheless, ERCOT did not pursue the MRA options or defer the project, due the risk of retirement of existing generation within the area and several pragmatic issues associated with the MRAs. First, ERCOT noted that it cannot compel generation or demand response to locate in a given area and participate in the market. Furthermore, ERCOT noted that there is currently no mechanism in place to call on demand response for a transmission security issue, eliminating demand response as a feasible alternative.[72]

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[71] ERCOT Board of Directors Resolution. April 8, 2014. http://www.ercot.com/content/meetings/board/keydocs/2014/0408/8_ERCOT_Independent_Review_of_the_Houston_Import_Regional_Pl.pdf

[72] ERCOT. *ERCOT Independent Review of Houston Import Regional Planning Group Project.* February 20, 2014. http://www.transmissionhub.com/documents/2014/03/ercot-final-report-houston-import-study-feb-20-2014-pdf.pdf

To date, ERCOT has not yet selected an MRA over a transmission project. This is likely because most transmission projects in ERCOT have been driven either by: (1) reliability needs, where MRAs that satisfy the reliability needs have not been identified; or (2) state policy (the Competitive Renewable Energy Zones ("CREZ")). More importantly, ERCOT has explicitly stated that it does not have control over certain MRAs (new generation and demand response), and as such, cannot consider them as feasible alternatives to reliability-driven projects.[73]

Complementarity of Transmission and MRAs in Texas

The CREZ effort, which involved a series of transmission projects including upgrades to existing infrastructure as well as the construction of new transmission lines, was designed to bring over 18,000 MW (nameplate) of wind capacity to market (primarily from Western Texas).

Although the initiative was not driven purely by economics, the Public Utility Commission of Texas ("PUCT") evaluated the cost-effectiveness and economic benefits of the CREZ projects. In addition to meeting the Legislative goal, CREZ was expected to bring air quality and water conservation benefits as well as additional system benefits since the CREZ lines are open-access (that is, the CREZ lines also enabled the build out of traditional fossil-fired generation away from load pockets). The CREZ project is an example of how transmission can accommodates and, in fact, promote MRAs – the CREZ transmission investments were made in order to provide access to market for existing and new wind generation and allow Texas to achieve legislated renewable energy goals.

However, recent experience in Texas also provides a good example of how transmission can in turn motivate MRAs, namely additional generation. Indeed, in the case of the Competitive Renewable Energy Zones ("CREZ") initiative in ERCOT, the driver of the transmission build out was the future development of renewable (wind) generation (see Text Box).

2.1.3 Independent System Operator of New England

ISO-NE has examined in the past how to consider MRAs in its transmission planning process. A number of pilot studies have been performed.

In its compliance filing with FERC, ISO-NE asserted that the existing provisions of its Attachment K met Order 1000's requirement that "non-transmission alternatives be considered on a comparable basis, and required identification of how evaluation and selection from

[73] "It should be noted that ERCOT cannot compel generation or demand response to locate in a certain area and participate in the ERCOT market. Therefore, ERCOT must plan transmission projects when reliability criteria violations are found." *See:* ERCOT. *ERCOT Independent Review of Houston Import Regional Planning Group Project.* February 20, 2014. P 37. http://www.transmissionhub.com/documents/2014/03/ercot-final-report-houston-import-study-feb-20-2014-pdf.pdf

competing solution and resources will be made so that resources are considered on a comparable basis."[74] Indeed, FERC had already approved ISO-NE's process for considering MRAs when it accepted ISO-NE's compliance filing for Order 890. FERC confirmed that Order 1000 did not impact those requirements, and therefore, ISO-NE's current process for including MRAs is still acceptable.[75]

ISO-NE's Transmission Planning Process

ISO-NE's planning process begins with high-level studies by ISO-NE and the New England Transmission Owners ("NETOs") to identify potential future reliability issue based on the NERC and Northwest Power Coordinating Council standards and criteria. Once ISO-NE decides that further review is needed, ISO-NE will initiate formal studies and present those study results to the Planning Advisory Committee ("PAC"). The process continues with ISO-NE releasing a formal Needs Assessment, identifying a reliability need and reviewing potential solutions. As part of the compliance filings, ISO-NE stated that

> *"…Part of ISO-NE's Needs Assessment includes consideration of market alternatives, which include both merchant transmission solutions and Non-Transmission Alternatives or NTAs. If the ISO concludes that alternatives have come forward in the marketplace that would resolve or delay the reliability need, it has the authority to decide that regulated transmission solutions will not be required or will be postponed. Under the regional planning process in New England, market solutions are favored over regulated transmission solutions if the ISO decides that the former will resolve the identified Need; for this reason, regulated transmission projects to resolve identified needs are referred to as 'backstop solutions.'"*[76]

Similar to PJM (discussed in Section 2.1.6), energy efficiency and demand response that cleared in the Forward Capacity Auction ("FCA") are included in the load forecast used for the transmission planning. In 2011, ISO-NE modified its forecasting methodology and started to project additional energy efficiency in the longer run, above the amount that had cleared in the latest FCA. The incremental amount of energy efficiency above the cleared FCA level is based on long-term studies reviewed and provided by state commissions. These incremental resources usually secure long-term full funding through various state programs and have a higher likelihood of remaining in the market.

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[74] Order No. 1000 Compliance Filing of ISO New England Inc. and the Participating Transmission Owners Administrative Committee, page 37. https://www.ferc.gov/industries/electric/indus-act/trans-plan/filings.asp

[75] FERC required ISO-NE to resubmit its compliance filing for Order 1000 due to short-comings of ISO-NE's filing related to other requirements of Order 1000. ISO-NE re-submitted its Compliance Filing to address FERC concerns and, as of May 2014, ISO-NE is still waiting for FERC to issue an order on its follow-up compliance filing.

[76] *Ibid.*

Categories of Transmission Projects

ISO-NE categorizes transmission projects either as reliability projects or market efficiency projects. Reliability projects are those projects that can meet the reliability needs identified by ISO-NE in its needs assessment study. Typically, ISO-NE's needs assessment studies evaluate the need for reliability projects; however, stakeholders may request a needs assessment for a market efficiency project (i.e., an economic study). Market efficiency projects are those projects that could result in production cost savings, reduced congestion, or the integration of new resources or load. ISO-NE then selects "the most cost-effective and reliable solutions for the region that meets a need identified in a Needs Assessment."[77]

Figure 29. Metrics Considered in ISO-NE's Transmission Planning Process

Project Category	Metrics Considered
Reliability	✓ Technical viability ✓ Costs
Market Efficiency	✓ Technical viability ✓ Production cost savings ✓ Reduced congestion ✓ Ability to integrate new load or resources

Recent Developments

To date, ISO-NE has conducted numerous pilot MRA analyses. In April 2011, the pilot study for New Hampshire/Vermont was presented at the PAC. This study looked at the ability of various sizes and locations of new hypothetical demand and supply resources to resolve the identified reliability needs in the two-state region. The analysis identified the critical load levels and hypothetical supply-side units that could eliminate thermal overloads for normal and contingency conditions. However, no cost estimate was provided. In December 2012, the ISO-NE conducted another pilot study, this time for the transmission needs in Greater Hartford/Central Connecticut. The pilot project concluded that approximately 950 MW of optimally located generation resources, along with associated transmission system upgrades, would be needed to resolve all the identified thermal system needs. Alternatively, the study concluded that 1,350 MW of demand resources (equivalent to 47% of the area's projected 90/10 peak load) would eliminate thermal overloads in the area.[78] ISO-NE found the MRA studies highlighted the significant challenges of using MRAs to resolve the identified needs. These challenges include the large number of necessary resources, as well as the co-dependency between the resources needed and the need for additional transmission upgrades should these

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[77] ISO-NE. Attachment K: Regional System Planning Process. 4.2(b).

[78] ISO-NE, 2013 Regional System Plan. <http://www.iso-ne.com/trans/rsp/index.html>

resources qualify in the Forward Capacity Market ("FCM"). Currently, an enhanced approach is being pursued on a pilot basis in 2014 for the SEMA-RI needs assessment and the preliminary result was presented in the PAC meeting in April.

On several occasions, New England states siting authorities have also pursued MRA analysis. For example, MRA analyses were conducted for Connecticut's Siting Council for the Greater Springfield Reliability Project ("GSRP") component of the New England East-West Solutions ("NEEWS") project. An economic valuation of MRAs supported the construction of the transmission project. MRA analyses were also conducted for Rhode Island Energy Facility Siting Board for Rhode Island Reliability Project ("RIRP") and Interstate Reliability Project ("Interstate"). RIRP is already in service. Interstate is not under construction, but ISO-NE has confirmed its need.

Similarly, an MRA analysis was completed for the Maine Power Reliability Project ("MPRP") at the request of the Maine Public Utility Commission ("MPUC"), after which the regulator determined that the transmission project was a preferred solution to meet reliability needs.

Similar to California, the state of Maine takes additional steps in considering MRAs in the transmission planning process. For example, the state of Maine recently passed new transmission planning requirements. The MPUC now must evaluate MRAs for all new transmission lines or transmission upgrades and give preference to MRAs when they will lower costs and reduce emissions.[79] In 2012, MPUC established the Boothbay Smart Grid Reliability Pilot project ("Boothbay Pilot") to test if MRAs can solve electric grid reliability needs at lower costs and with less pollution than new transmission lines or transmission system upgrades. We will discuss the Boothbay Pilot further in Section 3.1.

2.1.4 Midcontinent Independent System Operator

The MISO Transmission Expansion Planning ("MTEP") process, which was put in place prior to Order 1000, includes a regional transmission planning process that identifies and implements efficient and cost-effective regional transmission solutions. FERC found that MISO's treatment of MRAs is in compliance with FERC Order 1000 and agreed that MRAs are considered on a comparable basis in the transmission planning process. Specifically, FERC state that MISO's "Tariff and the Transmission Planning Business Practice Manual already provide sufficient detail about how stakeholders can propose, and how MISO will evaluate on a comparable basis, any alternative to an identified need."[80]

To date, however, no MRA has been selected in lieu of a traditional transmission project or otherwise delayed the need for a transmission project. MISO has not specified any MRA types other than demand response and generation. However, MISO includes energy efficiency and

[79] 35-A M.R.S.A. §§3132, 3231-A

[80] FERC. Order on Compliance Filings and Tariff Revisions. Page 18. Docket No. ER13-187-000, et al. March 22, 2013. <http://www.ferc.gov/whats-new/comm-meet/2013/032113/E-2.pdf>

distributed generation within the broad class of demand response resources, as we discuss further below.

MISO's Transmission Planning Process

MISO evaluates project submissions from Transmission Owner ("TO") members through an annual series of internal analyses and discussions of these projects, i.e., Sub-regional Planning Meetings ("SPMs") (which occur in each of the four sub-regions of MISO - West, Central, East and South). SPM participants include MISO planning staff, transmission owners, and any parties interested in or impacted by the planning process. MRAs are currently considered at the beginning of the transmission planning process and are discussed as early as in the first SPM.

Under the SPM process, MISO staff, in collaboration with TOs and stakeholders, performs reliability and economic analyses needed to assess reliability and economic benefits, review cost estimates of identified alternatives, and evaluate projects to determine the preferred solution.

For generation resources, planning models of five years or longer are used, taking into consideration applicable planning reserve requirements that are:

- existing and anticipated requirements in the planning horizon timeframe;
- not existing requirements, but those with executed interconnection agreements; and
- additional generation as determined with stakeholder input, as necessary to "adequately and efficiently meet demand forecasted through the planning horizon and to facilitate compliance with statutory or regulatory mandates."[81]

MISO then applies a scenario analysis to determine alternative future generation portfolio possibilities. Generation portfolio development for planning model purposes is developed with input from the Planning Advisory Committee and its subcommittees, working groups, and task forces. Point-To-Point Transmission Service and Network Integration Transmission Service customers have an opportunity to guide new generation portfolio development that is reflective of their future resource plans.

For demand response resources, planning solutions are based upon the best available information regarding the expected amount and location of load that can be effectively and efficiently reduced by demand response or energy efficiency programs. Additionally, the amount of behind-the-meter generation (i.e., distributed generation) that can reliably be expected to produce energy that could impact planning solutions is also considered as part of the planning solutions stage. In theory, MISO considers all major types of MRAs. However, like ERCOT, MISO recognizes that it cannot obligate MRAs to build, and there may be uncertainties over the permanency of MRAs over time as market conditions evolve. Therefore, transmission projects are typically chosen for meeting system reliability needs. MISO reports the findings of its sensitivity analyses, which indicate the effectiveness of potential demand response as alternative planning solutions, to the extent that appropriate methodology for such analyses is

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[81] Attachment FF, pg. 19

developed with stakeholders and documented in the Transmission Planning Business Practices Manual ("TPBPM").[82]

Categories of Transmission Projects

MISO classifies transmission projects into three broad categories: reliability projects,[83] market efficiency projects, and multi-value projects ("MVPs"). Reliability projects are those projects that are required to resolve identified reliability needs. Market efficiency projects are projects that reduce market congestion. Market efficiency projects are evaluated based upon production cost savings. Market efficiency projects with a benefit to cost ratio of 1.25 or greater are eligible for regional cost sharing. Multi-value projects are projects that provide regional public policy, economic, and/or reliability benefits. MVPs are evaluated on benefits such as congestion and fuel savings, decreased operating reserves, decreased system planning reserve margin, decreased transmission line losses, production cost savings, and public policy and other qualitative benefits. However, MVPs must have a benefit to cost ratio of 1.0 or more to qualify for regional cost sharing. The benefits considered include all financially quantifiable benefits provided by the project, as summarized in Figure 30.[84]

Figure 30. Metrics Considered in MISO's Transmission Planning Process

Project Category	Metrics Considered
Reliability	✓ Technical viability ✓ Cost
Market Efficiency	✓ Production cost savings ✓ Ability to relieve congestion ✓ Technical viability
Multi-value	✓ Technical viability ✓ Congestion and fuel savings ✓ Decreased operating reserves ✓ Decreased system planning reserve margin ✓ Decreased transmission losses ✓ Production cost savings ✓ Public policy ✓ Other qualitative benefits

[82] Ibid. pg. 20

[83] For ease of reference, LEI has grouped MISO's Transmission Service Request, Interconnection Request, Reliability, and other projects into the single category of reliability.

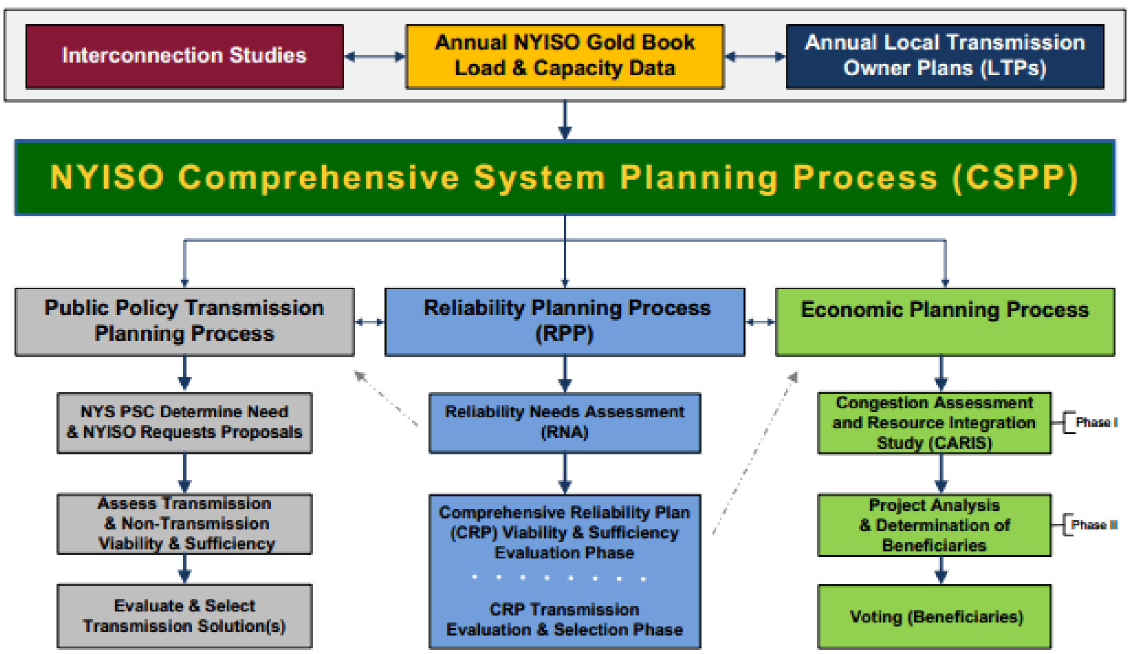
[84] MISO Attachment FF.

2.1.5 New York Independent System Operator

NYISO's Transmission Planning Process

In NYISO, MRAs are considered in the comprehensive system planning process ("CSPP"), which was described in the Compliance Filing on Order 1000.[85] The CSPP takes place every two years, and consists of four components: the local transmission planning process ("LTPP"), the reliability planning process ("RPP"), an economic planning process, known as the Congestion Assessment and Resource Integration Study ("CARIS"), and a public policy transmission planning process as shown in Figure 31.[86]

Figure 31. NYISO Comprehensive System Planning Process



Source: NYISO. *NYISO 2013 Congestion Assessment and Resource Integration Study*. P. 20

The first component, the Local Transmission Planning Process ("LTPP") feeds into the system-wide Reliability Planning Process ("RPP"), which results in the Reliability Needs Assessment ("RNA") report and the Comprehensive Reliability Plan ("CRP") report. The RNA is a ten-year assessment of resource adequacy and transmission security, which determines if reliability

[85] NYISO. *New York Independent System Operator, Inc and New York Transmission Owners, Compliance Filing, Docket Nos. RM10-23-000, ER13-_____-000*. October 11, 2012.

[86] NYISO. *NYISO 2012 Comprehensive Reliability Plan*. p 8.

criteria are met.[87] If the reliability criteria are not met, the RNA identifies reliability needs, and NYISO requests both market and regulated solutions from developers for NYISO to evaluate.

Importantly, "all resource types (generation, transmission, and demand-side management) are considered on a comparable basis as potential solutions."[88] NYISO's findings and recommendations are then published in the CRP. The CRP includes all of NYISO's recommendations for solution(s) for reliability needs, which can include MRAs. The 2010 RNA did not identify any reliability needs (likely due to low load growth), and therefore NYISO did not solicit and evaluate any solutions (either transmission or MRAs) for the 2010 CRP.[89] There were, however, MRAs proposed in the 2012 CRPP (see text box below).

MRAs and the 2012 CRPP

The 2012 CRPP concluded with the release of the CRP (issued in March 2013), which advised that additional resources are needed over the last two years of the Study Period (the Study period was 2013-2022). Additional resources were needed in order for the New York Control Area ("NYCA") to be in compliance with applicable reliability criteria. Based upon its evaluation of the market-based solutions and the most recent LTPs from the TOs, the NYISO has concluded that there are sufficient proposed market-based resource additions which, if developed, would allow the NYCA to be in compliance with the resource adequacy criteria for the next 10 years. As a result, no regulatory solution was triggered and no transmission investment was required. Three market based solutions were identified by the NYISO based on proposals it received in response to the CARIS report, and these were:

- NRG Plan for Astoria Repowering;
- NRG Plan For Repowering Zone A Resources; and
- Plan to increase Demand Response in Zone J.

Specifically, for the last solution, Constellation NewEnergy, Inc. submitted plans to increase special case resources (demand side resources) in Zone J by 30 MW in response to resource adequacy needs that arise in 2021. The resources would be added over the years 2014 – 2018.

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87 Reliability needs are measured both in terms of system security and adequacy. System security is the ability to withstand sudden disturbances, and is measured deterministically. Resource adequacy is the ability for the system to supply the total demanded quantity of energy, and is measured probabilistically. New York's bulk power system is planned to meet a Loss of Load Expectation of less than once every ten years.

88 NYISO. *Reliability Planning*. Accessed 5/6/2014. http://www.nyiso.com/public/about_nyiso/fundamentals_of_planning/reliability_planning/index.jsp

89 NYISO, 2010 Comprehensive Reliability Plan, page 26. <http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Reliability_Planning_Studies/Reliability_Assessment_Documents/CRP_2010_FINAL_REPORT_January_11__2011.pdf>

The economic planning process, known as CARIS, follows the approval of the CRPP, and is comprised of a study phase and a project phase. For the study phase, the top three congested elements of the New York bulk power system are identified, and generic solutions are evaluated using a ten-year projection of production cost savings. Generic solution types include "transmission, generation, energy efficiency and demand response."[90] Although production cost savings are the primary metric, changes to locational based marginal pricing, generator costs, installed capacity costs, emission costs, and transmission congestion contract costs are also presented. The study phase does not recommend specific projects or types of projects; the information is meant to inform developers on whether to propose such projects for official NYISO review.

Developers of economic transmission projects can then request the NYISO to conduct the project phase of CARIS (at the developer's expense), resulting in additional analysis for regulated cost recovery. Economic transmission projects are eligible for regulated cost recovery through the NYISO tariff if they have a benefit to cost ratio of greater than 1,[91] cost at least $25 million, and have over 80% of a weighted vote of load serving entities ("LSEs") serving load zones which are beneficiaries of the project.

Under the fourth component, the Public Policy Transmission Planning Process, parties propose solutions to identified transmission needs driven by public policy requirements. NYISO evaluates the ability of the proposed solution to meet the need, and then selects the most cost-effective solution to the identified need.

Categories of Transmission Projects

In NYISO, transmission projects fall into one of three categories: reliability projects, economic projects, or public policy projects. All three are evaluated to determine the technical viability and sufficiency of the proposed projects. However, they vary in how the costs and benefits are considered. Reliability projects and public policy projects are evaluated on metrics such as capital costs, cost per MW ratio, expandability, operability and performance, availability of property rights, and schedule for completion to determine the most efficient or cost-effective solutions. Economic projects are evaluated based on production cost savings and must have a benefit to cost ratio greater than 1 to qualify for regulated cost recovery.

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[90] NYISO. *NYISO 2013 Congestion Assessment and Resource Integration Study*. P. 19

[91] The benefit cost ratio compares the present values of ten years of benefits and costs.

Figure 32. Metrics Considered in NYISO's Transmission Planning Process

Project Category	Metrics Considered
Reliability	✓ Technical viability ✓ Capital costs ✓ Efficiency (expandability, operability, and performance; availability of property rights; schedule for completion)
Public Policy	✓ Technical viability ✓ Capital costs ✓ Efficiency (expandability, operability, and performance; availability of property rights; schedule for completion) ✓ Ability to meet identified public policy need
Economic	✓ Technical viability ✓ Efficiency (expandability, operability, and performance; availability of property rights; schedule for completion) ✓ Product cost savings ✓ Ability to reduce congestion

2.1.6 Pennsylvania-New Jersey-Maryland Interconnection

In PJM, the Regional Transmission Expansion Plan ("RTEP") had taken into consideration the MRAs before Order 1000, based on the investment activity that PJM observes in the wholesale capacity market (i.e., Base Residual Auction results). As mentioned in more detail below, the RTEP takes into account the resources (generation as well as demand response) that cleared in the RPM as well as the projected load forecasts (which include energy efficiency) when it analyzes system reliability and develops transmission studies.

PJM's Transmission Planning Process

PJM has stated that it believes that its planning process provides opportunities for MRAs to compete with transmission solutions on a comparable basis through various market structures. For instance, the resources that have cleared PJM's capacity market produce firm commitments for new demand response, energy efficiency, and generating resources to meet forward projected load. The availability of these resources on a forward basis is then factored into future RTEP planning analyses. PJM's analysis is based on the premise that these market-based resources, who have committed to the market in advance[92] (and are being remunerated through market mechanisms), may pre-empt the need for transmission solutions.

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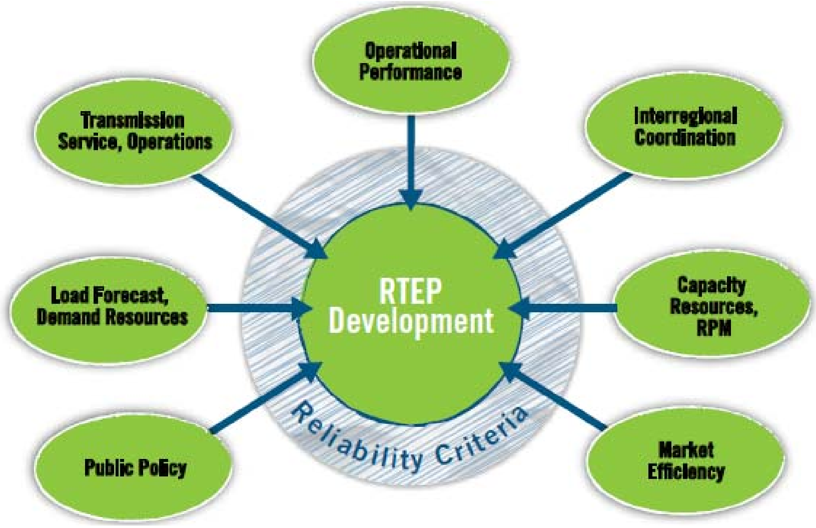
[92] PJM's capacity market, Reliability Pricing Model ("RPM"), is a three year forward market.

Even after transmission solutions are identified and approved by the PJM Board, PJM continues to re-evaluate the expected market conditions as new information becomes available or existing information is verified. For example, demand response solutions enter the PJM process in the Reliability Pricing Model ("RPM") through the associated base residual and incremental auctions. The DR cleared in the auction is included in the assumptions for RTEP development and physically modeled in the baseline power flows. In this manner, load can mitigate or delay the need for RTEP upgrades.

PJM revisits its RTEP at least annually to examine any need to revise, defer, or cancel approved enhancements and expansions, due to revised load forecasts, changes in availability of demand side response and energy efficiency resources, and changing generation fleet portfolio. For example, PJM's transmission planning has included in past studies changes to system conditions brought about by load fluctuations and new generation investment. Figure 33 shows the factors that PJM considers in the RTEP development.

Figure 33. Factors considered in the RTEP development



Source: PJM RTEP

PJM's regional transmission planning analyses (through sensitivity studies, modeling assumption variations, and scenario analyses) in intended to take account of known changes in expected future system conditions, including, but not limited to: load levels; transfer levels; fuel costs; the level and type of generation; generation patterns; demand response; and uncertainties arising from estimated times to construct transmission upgrades. However, PJM uses strict reliability metrics and assumptions to determine which projects can be included in the RTEP (a process known as the "bright-line test"). Under the bright-line test, PJM typically does not conduct sensitivity studies or scenario analysis, nor does it vary its model assumptions to reflect the dynamics of the market in the long-run. PJM has recognized that this bright-line test is not flexible enough to identify the most effective solutions to meet the system needs in the long-run and is in the process of moving toward a more balanced planning approach (see Section 3.3 for more detail).[93]

In summary, MRAs are considered in the regional planning process via the sensitivity studies and scenario analyses, which will be subject to stakeholder input and review. However, based on the prescriptive approach, dynamic changes in investments are not captured. In addition, economic benefits are not always examined.

Categories of Transmission Projects

In PJM, there are two categories of transmission projects: reliability and market efficiency. However, PJM is in the process of incorporating public policy projects as well. Reliability projects are evaluated on their ability to meet identified reliability needs. Market efficiency projects are those projects that lower costs to customers by relieving congestion. Market efficiency projects are first evaluated based on their benefit to cost ratio, which must meet or exceed 1.25. Those projects that meet the benefit to cost ratio requirement are then evaluated to determine their impact on system reliability. Benefits are measured on average weighted basis (50% in production costs and 50% change in net load energy payments). For reliability projects, market efficiency analysis is an incremental analysis, and may be conducted as a sensitivity analysis. The decision to keep, defer or cancel is based on analysis that only focuses on reliability.

Figure 34. Metrics Considered in PJM's Transmission Planning Process

Project Category	Metrics Considered
Reliability	✓ Technical viability ✓ Capital costs
Market Efficiency	✓ Technical viability ✓ Reduce congestion ✓ Production cost savings ✓ Net load energy payment
Public Policy	Under development

Recent Developments

Two good examples can be drawn from the 2012 RTEP. PJM determined the need for the Potomac-Appalachian Transmission Highline ("PATH") and Mid-Atlantic Power Pathway ("MAPP") projects in 2007. These projects have a combined total cost of over $3.2 billion. With the decrease in load due to the recession and the increase in demand response resources, as well as new generation that cleared in the capacity market, PJM decided that the PATH and MAPP lines were no longer required and were removed from the 2012 RTEP. A more detailed discussion can be found in Chapter 3.

93 FERC Docket ER12-1178. PJM Tariff Filing. February 12, 2012.

2.1.7 Southwest Power Pool

Through its Integrated Transmission Planning ("ITP") process, SPP complies with the regional transmission planning requirements of Order 1000.[94] As part of its ITP, SPP, in consultation with stakeholders, evaluates MRA solutions that may meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in the local transmission planning process. To date, however, similar to MISO, no MRA has been selected in lieu of a traditional transmission project or delayed the need for a transmission project.

SPP's Transmission Planning Process

Per Section III.8 (d) of Attachment O, SPP considers, on a comparable basis, any alternative proposals, which may include, but are not limited to: generation options, demand response programs, smart grid technologies, and energy efficiency programs. According to Attachment O, SPP will evaluate solutions against each other based on a comparison of their relative effectiveness of performance and economics. SPP's transmission planning process starts at local level, because transmission solutions are first identified by individual public utility transmission providers in their local transmission planning process.[95] At this level, various scenarios or future conditions on new generation or demand are considered.[96] SPP then provides stakeholders with an initial list of cost-effective transmission solutions to meet the region's needs. Once stakeholders have had a chance to review the initial list, the ITP process requires that SPP consider and evaluate, on a comparable basis, any alternative proposals, which could include, but would not be limited to generation options, demand response programs, "smart grid" technologies, and energy efficiency programs that will meet the needs of the transmission planning region more efficiently or cost-effectively.[97]

The ITP process is an iterative, three-year planning process that includes 20-year, 10-year, and near-term assessments designed to identify transmission solutions that address both near-term and long-term transmission needs. The ITP process concludes with an identification of the preferred, cost-effective regional transmission solutions, and the release of the SPP Transmission Expansion Plan ("STEP") report. SPP is required to produce the STEP report

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[94] FERC. Order on Compliance Filings. SPP. Docket Nos. ER13-366-000; ER13-367-000. July 18, 2013. Pg 23.

[95] The FERC Order noted that "*With the exception of SPS, the transmission owners that belong to SPP do not have local transmission planning processes separate from regional planning. Section II.5 of Attachment O of SPP's OATT provides that SPP evaluates both regional and local planning criteria. Thus, for these public utility transmission providers, Order No. 1000's requirements with regard to public policy requirements apply only to the regional transmission planning process, consistent with Order No. 1000.*"

[96] SPS 10-year Plan, December 2012. http://www.xcelenergy.com/staticfiles/xe/Corporate/Corporate%20PDFs/SPS_2012_10Year_Plan.pdf

[97] SPP OATT Attachment O.

annually.[98] SPP characterizes the STEP report as a comprehensive listing of all transmission projects in SPP over a 20-year planning horizon. The projects are identified and recommended in the STEP/ITP process, which is followed by Board approval for funding. The STEP reports state that: "ITP projects are reviewed by SPP's Transmission Working Group ("TWG"), Markets and Operations Policy Committee ("MOPC"), and approved by the Board of Directors. Following Board of Directors' approval, staff will issue Notification to Construct ("NTC") letters for upgrades that require a financial commitment within the next four-year timeframe." This includes projects identified during the ITP process as well as other projects, such as generation interconnection projects and projects required to satisfy requests for transmission service. Based on LEI's review of latest available (2013) STEP report,[99] no official MRAs have been proposed.

Categories of Transmission Projects

SPP employs an integrated transmission planning, where proposed projects are not classified narrowly. Transmission projects, as a whole, are selected for their ability to meet reliability, economic, and/or public policy needs. SPP also considers Balanced Portfolio projects, which are projects that reduce congestion whose costs can be allocated regionally. Balanced portfolio projects are selected if the benefits outweigh the costs.[100] SPP generally considers a variety of metrics when evaluating transmission, as shown in Figure 35.

Figure 35. Metrics Considered in SPP's Transmission Planning Process

Project Category	Metrics Considered
ITP	✓ Technical viability ✓ Production cost savings ✓ Marginal energy losses benefits ✓ Mitigation of transmission outages/losses, ✓ Capacity savings ✓ Avoided or delayed reliability projects, ✓ Reducing the cost of extreme events, ✓ Assumed benefit of mandated reliability projects, ✓ Reduction of emission rates and values ✓ Savings due to lower ancillary service needs ✓ Increased wheeling revenues ✓ Benefit from meeting public policy goals

98 FERC. Order on Compliance Filings. SPP. Docket Nos. ER13-366-000; ER13-367-000. July 18, 2013. Pg 18. <https://www.ferc.gov/whats-new/comm-meet/2013/071813/E-2.pdf>

99 SPP. *2013 SPP Transmission Expansion Plan Report*. January 29, 2013.

100 SPP. 2013 STEP Report.

2.2 Consideration of MRAs in Current Planning Processes for Non-RTO Regions

In regions where no RTO exists, transmission planning is first performed at the local level and then performed at the regional level in accordance with the requirements of FERC Order Nos. 890 and 1000. MRAs are considered in an implicit or passive manner in the context of the utility's integrated resource plan ("IRP"). Although a comprehensive review of all regulated utilities in the U.S. is outside the scope of this paper, based on our general familiarity with IRPs in the Southeast and Western U.S., the IRP processes generally consider energy efficiency based demand and energy savings as a reduction to the load forecast. Other demand-side resources – like demand response, and distributed generation – are treated as "dispatchable" resources that can be dispatched to meet system capacity needs during periods of peak demand. In the non-RTO regions, demand response is considered in the local and regional transmission planning processes in compliance with the FERC directives established in Orders Nos. 890 and 1000.

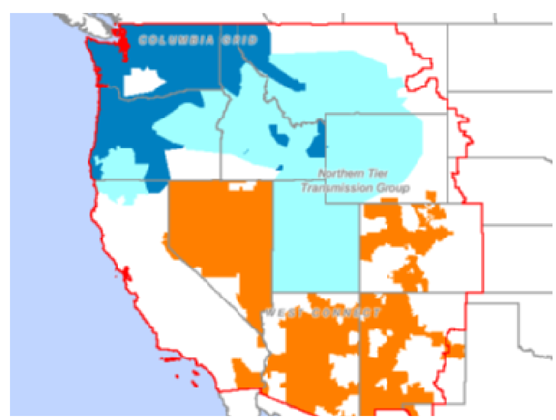
2.2.1 SERC

In the southeast, a regional entity known as the Southeastern Regional Transmission Planning ("SERTP") group[101] has been created in order to comply with Order 1000, effective June 1, 2014.[102] The SERTP Sponsors first consider MRAs during the development of their individual IRPs and then offer the opportunity to further evaluate MRA opportunities within the directives established within Order Nos. 890 and 1000 during their local and regional transmission planning processes.

2.2.2 WECC

On the other side of the country, in the non-California part of the Western Electricity Coordinating Council ("WECC"), the level of MRA compliance varies. This region is divided into three grids: Northern Tier Transmission Group ("NTTG"), WestConnect, and ColumbiaGrid. Based on LEI's review of the compliance filings, while NTTG is in full compliance with the MRA requirements of Order 1000, WestConnect and ColumbiaGrid are in partial compliance.

Figure 36. Map of NTTG, WestConnect and ColumbiaGrid



[101] http://www.southeasternrtp.com/

[102] FERC's approval of the June 1, 2014 implementation date was provided on October 17, 2013 in their Order under the following FERC Dockets: ER13-83; ER13-897; ER13-908; and ER13-913.

2.2.2.1 WECC - NTTG

In NTTG's compliance filing with FERC, it states its intent to assess MRAs as part of the interregional planning process, committing its transmission utility members to each use their "best efforts to facilitate NTTG conducting its regional process, using identified regional transmission service and non-transmission alternatives, to identify regional transmission projects (if any) that are more efficient and cost-effective from a regional perspective than the transmission projects identified in the participating transmission providers' local transmission plans."[103]

It is currently anticipated that the initial regional transmission plan(s) will be incorporated with the appropriate WECC-wide base case(s) for the NTTG's Planning Committee's review, and then the NTTG Planning Committee will confirm/identify regional transmission project or MRAs that will likely result in a more efficient or cost-effective plan. The NTTG regional planning process lasts for two years. During the first quarter, transmission providers, merchant project developers, and stakeholders provide information about any proposed MRAs to the planning group. MRA projects can be submitted to meet reliability or load service requirements, address economic considerations, and/or to meet transmission needs driven by public policy needs.[104] This information can be updated in the fifth quarter, if necessary. A Study Plan will be developed in the second quarter, which will delineate the method of study to evaluate the transmission and MRAs that have been proposed (there is not a specific methodology in place). The initial plan (comprising the transmission and MRAs) proposed in the first quarter will then be analyzed to arrive at an efficient, cost-effective regional transmission plan. It, however, has not yet been implemented yet.

2.2.2.2 WECC - WestConnect

In WestConnect, as part of the planning process, any stakeholder may submit proposals for MRAs; however, MRAs will not be eligible for cost allocation. Based on FERC's latest decision on WestConnect's Order 1000 Compliance filing, in order to comply fully, WestConnect must still amend the Open Access Transmission Tariffs ("OATTs") to explicitly state that MRAs will have the opportunity to demonstrate that information required for a project submittal in the regional transmission process should not be required for a specific MRA, in order to put MRAs on equal footing with transmission proposals. In addition, filing parties at WestConnect must revise their OATTs to remove the $25,000 filing fee that MRAs must pay to propose a project. FERC found that this fee should not be assessed for MRAs, since they are ineligible for regional cost allocation (while proposed regional transmission projects must pay the fee since they are eligible for cost recovery through regional cost allocation).

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103 FERC Order on NTTG's compliance filing. Page 25-26. FERC Docket No. ER13-64. 143 FERC ¶ 61,151. Order on Compliance Filing. Issued May 17, 2013.

104 NTTG Planning Practice Document, Page 5. <http://nttg.biz/site/index.php?option=com_docman&task=doc_details&gid=1721&Itemid=31>

2.2.2.3 WECC - ColumbiaGrid

Same as the WestConnect, the parties filing in ColumbiaGrid are partially in compliance with Order 1000. In its filing with FERC, ColumbiaGrid states that MRAs are

> *"an alternative that does not involve the construction of transmission facilities and that ColumbiaGrid has determined would result in the elimination or deferral of a Need by modifying the loads or resources reflected in the system assessments. Examples of such alternatives that may constitute Non-Transmission Alternatives may include demand-side load reduction programs, peak-shaving projects, and distributed generation. The following examples are specifically excluded from Non-Transmission Alternatives: remedial action schemes, shunt capacitors, and reconductoring."*[105]

However, ColumbiaGrid's proposed planning process states that a study team must determine if an MRA has a "reasonable degree of development" before it can be noted in the transmission plan, but do not explain how a "reasonable degree of development" will be determined. Furthermore, FERC found that ColumbiaGrid "Filing Parties also do not explain how applying this new, additional factor only to non-transmission alternatives complies with the requirement to evaluate and select from competing solutions and resources such that all types of resources are considered on a comparable basis."[106] FERC has requested that ColumbiaGrid amend their proposal to address these concerns of equal footing, in order to fully comply with Order 1000.

2.3 Key Takeaways

To date, FERC has approved all RTO Order 1000 compliance filings as they relate to MRAs (RTOs may still be working meet other requirements of Order 1000). However, while MRAs may be implicitly considered in the transmission planning process in RTOs across the U.S., there are few examples of the explicit consideration of MRAs to date. However, there are still a few key observations that can be made:

There is some ***uncertainty as to what technologies are considered as MRAs*** – some system planners consider either explicitly or implicitly EE, DR and conventional generation since these are more "commercially" known and these resources generally can clear capacity markets. Other technologies may not always be considered, if planners do not know all the attributes and benefits of that MRA.

When MRAs are considered, ***ISO/RTOs have typically looked at specific types of MRAs and considered them in a "silo"***. But in the future it may be best to think about planning on a more ***integrated, portfolio basis***.

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[105] ColumbiaGrid Compliance Filing. <http://www.ferc.gov/industries/electric/indus-act/trans-plan/filings.asp>

[106] FERC Order on ColumbiaGrid Compliance Filing. FERC Docket No. ER13-94 et al. 143 FERC ¶ 61,255. Issued June 20, 2013.

There is general ***lack of experience*** in addressing uncertainty in future outcomes – specifically as they relate to questions of permanence or duration of market participation by MRAs and geographical breadth of various investments, including both transmission and MRAs.

A limited set of metrics have been used to date to evaluate transmission projects and MRAs. In most RTOs, projects are evaluated basic on their technical ability to meet an identified need and on cost. Production cost savings are typically used to determine the benefits. Only a few RTOs consider a broader range of benefits, such as CAISO and MISO in its MVP analysis.

Chapter 3: Case Studies

In this chapter, we provide four case studies of analysis of MRAs in the transmission planning setting: Boothbay Smart Grid Reliability Pilot project in Maine, I-5 Corridor Reinforcement Transmission Project by Bonneville Power Administration ("BPA"), PATH and MAPP transmission projects in PJM, and Tehachapi Renewable Transmission Project in California. In the process of selecting the case studies, we reviewed many possible case studies and settled on these four examples because, when taken together, they cover a variety of MRA technologies and investment needs, apply varying levels of analysis of MRA and transmission solutions, and highlight different aspects of the interplay between MRAs and transmission projects:

- ***The Boothbay Smart Grid Reliability Pilot project in Maine*** was driven largely by public policy goals, although the MRA-transmission solution was supposed to offer the same (if not better) level of reliability as a transmission only solution. It was a pilot project and therefore intentionally and explicitly considered a wide variety of MRAs including energy efficiency, demand response, energy storage, distributed generation, and back-up generation. The Pilot Project was focused on demonstrating the cost effectiveness and technical applicability of MRAs but did not fully address the varying benefits of MRAs. In addition, MRAs in the Boothbay pilot project were deployed to meet very specific and very local needs, and therefore the experiences may not be transferrable to other situations and locales.

- In the case study of ***the I-5 Corridor Reinforcement Transmission Project in BPA***, both MRAs and transmission solutions were considered to meet an identified reliability need. The MRAs considered included energy efficiency, demand response, distributed generation, and re-dispatch of existing generation. Ultimately, the transmission project was pursued, given a finding that MRAs were potentially insufficient and too risky to meet the identified reliability needs over the long term.

- In the case study of ***PATH and MAPP in PJM***, transmission projects that had been previously identified to meet reliability were reassessed in light of depressed demand, which was primarily driven by economic recession. As a result of the reassessment, the development of the transmission projects was postponed. Notably, PJM did not conduct a full economic cost-benefit analysis of the transmission projects, as they were originally designed as solutions to a reliability problem rather than a market efficiency upgrade. The PATH and MAPP projects highlight the importance of PJM's on-going effort of moving away from a bright-line reliability planning criteria to a more flexible and balanced approach.

- The ***Tehachapi Renewable Transmission Project in California***, like the Boothbay pilot, was largely driven by public policy goals. But unlike Boothbay, there was no explicit consideration of MRAs. In this instance, transmission projects were pursued to meet RPS goals. System planners implicitly leveraged the complementary relationship between transmission and wind generation (a type of MRA). Transmission investment was pursued in order to provide an opportunity for more generation (more MRAs) to be built and thereby promote public policy goals surrounding renewable portfolio standards. Interestingly, an economic evaluation of the Tehachapi Transmission project was not performed; however, CAISO's TEAM framework could have been deployed to establish the value of the transmission for promoting public policy goals and to measure the economic benefits to the MRAs that were catalyzed as a result of the transmission.

Figure 37. Summary of the case studies

	Boothbay Pilot	I-5 Corridor Reinforcement	PATH/MAPP	Tehachapi
Type of MRA Considered	✓ Back-up generation ✓ Demand response ✓ Distributed generation ✓ Energy efficiency ✓ Energy storage	✓ Demand response ✓ Distributed generation ✓ Energy efficiency ✓ Re-dispatch of existing generators	✓ Conventional generation ✓ Demand response ✓ Energy efficiency (implicit consideration in load forecast)	✓ Conventional generation (implicit)
Need	Public Policy, Reliability	Reliability	Reliability	Public Policy
Benefits considered/ analysis performed	Cost was primary criteria; reliability, diversity, and emissions reductions considered qualitatively	Total resource cost; participant cost; societal cost	Economic analysis not performed (focus on reliability)	Economic analysis not performed (focus on policy need)
Observations	▪ MRA resources may be available at reasonable cost to meet very specific and very local needs ▪ Deploying MRAs to address certain reliability needs may result in other reliability challenges ▪ Some MRAs are still not cost competitive ▪ Comprehensive, full scale cost-benefit analysis was not employed	▪ Without explicit consideration of uncertainty and timing issues, comparison of MRAs and transmission can yield misleading results ▪ There may be complementary relationship between transmission and MRAs, but it was not quantified in the analysis	▪ Ultimately, these projects were cancelled due to the demand reductions resulting from the recession, additional conventional generation and some demand response ▪ A more comprehensive analysis of load growth and capacity market uncertainty may have more fully reflected the insurance value of transmission ▪ An economic analysis of the full range of benefits provided by a project should be considered when evaluating transmission projects	▪ Transmission investment can serve as a complement to, and in fact a catalyst for, new generation ▪ Transmission can provide broader policy and macroeconomic benefits ▪ CAISO did not quantify those benefits or quantitatively evaluate the complementarity between transmission and new generation

In the following sections we will discuss these case studies in more detail. For each case study, we will first provide an overview of the project that is the focus of the case study, summarizing the key drivers behind the project and the types of MRAs considered (explicitly or implicitly). We will then discuss the analytical and methodological framework used to evaluate the proposed transmission solution and MRAs and arrive at a final decision (i.e., which transmission or MRA solutions were deployed). Finally, we will provide our key observations on each case study. These observations will be used to provide important input for the set of analytical tools and techniques that we will present in Chapter 4. Figure 37 above provides a brief summary of the case studies.

3.1 Boothbay Smart Grid Reliability Pilot project in Maine

Project Background

> **Agency/ entity responsible for decision-making and analysis**:
> - MPUC and GridSolar (project coordinator)
>
> **Observations**:
> - Gross costs (least cost framework) were the only criteria; gross benefits (or net benefits) were not considered
> - MRAs were pursued to meet very specific and very local needs
> - The process was driven largely by public policy goals
> - Scaling up could be difficult in a larger geographical area with greater needs

In 2012, the Maine Public Utilities Commission ("MPUC") developed the Boothbay Smart Grid Reliability Pilot ("Boothbay Pilot") project as part of an effort to identify possible MRAs to meet reliability needs identified as part of the Maine Power Reliability Program ("MPRP"). Specifically, the Boothbay project sought to reliably reduce transmission load by 2 MW in the Boothbay sub-region of Central Maine Power's ("CMP") electric grid in order to avoid the need for an estimated $18 million rebuild of a 34.5 kV electric line from Newcastle to Boothbay Harbor.

In order to fund the Boothbay Pilot, CMP designated 10% of the funding originally allocated for transmission line upgrades. The Pilot was designed and approved to advance the goals and policies of the Maine Smart Grid Policy Act. GridSolar LLC ("GridSolar") was designated as the project coordinator by the MPUC to solicit and evaluate MRA proposals using a competitive bidding process based on the cost and reliability.[107] The MPUC had required that a diverse set of MRA resources be examined. The Boothbay Pilot aims to answer four questions:

- whether and what types of MRAs can be acquired at reasonable cost to meet grid reliability requirements;
- whether and the best means by which the new Advanced Metering systems being deployed by CMP can provide the information and communications requirements to support MRA solutions to grid reliability issues;
- whether MRAs are capable of responding in the manner necessary to provide grid reliability service to CMP;
- whether the results of the Boothbay Pilot project can be scaled to meet the grid reliability requirements of other regions of the CMP and Emera networks in Maine.

Some of these questions have not yet been answered, but will be considered after the initial three year period is complete.

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[107] The MPUC issued an Order Approving Stipulation in Docket No. 2008-255 on June 10, 2010, which approved almost all the elements of CMP's Maine Power Reliability Program transmission project. In addition, this stipulation designated GridSolar as the "Smart Grid Energy Services Operator" for the MRA pilots within CMP's service territory to address the reliability needs in the Mid-Coast area as well as the Portland area.

To the extent feasible, GridSolar was directed by the MPUC to include a variety of MRA technologies: a minimum of 250 kW of MRA resources in energy efficiency, demand response, renewable distributed generation (at least half of which should be solar PV) and non-renewable distributed generation (with preference given to resources with no net emissions of greenhouse gasses). Selected MRA projects received a three-year contract (first phase), with a possible extension to 10 years if the first phase were considered successful. GridSolar explained that a project was viewed as "successful" as long as the MRA both cost less than the transmission alternative (i.e., annual revenue requirement) and proved to be reliable (i.e., no blackouts) throughout the three years. Notably, economic benefits of the MRAs relative to transmission were considered or evaluated during the initial process that led to the selection of the MRAs.

Analytical framework and methodology

GridSolar issued the MRA RFPs in two rounds. The first RFP was issued in September 2012, and resulted in 12 bids from six separate MRA resource providers totaling 4.5 MW. One bid for 1 MW was subsequently withdrawn by Maine Micro Grid for financing reasons.[108] In order to provide adequate interim reliability, MPUC directed GridSolar to install a temporary 500 kW back-up diesel generator, which was included in the RFP along with the other technologies. The second RFP was issued in May 2013, and resulted in 22 bids from 10 separate MRA resource providers totaling 4 MW. Both RFPs received bids in five MRA resource categories, including solar PV, efficiency, demand response, battery storage, and back-up generation ("BUG"). Dynamic pricing projects (e.g., smart meters) could not participate in the Boothbay Pilot due to limitations in the metering and billing infrastructure for this region of CMP's electric grid. The bids received in RFP I and II are shown in Figure 38 below.

Figure 38. Price comparison of all bids received in RFP I and II

10 year	RFP I			RFP II			
levelized cost	Bids	Capacity	$/kW month	Bids	Capacity	$/kW month	Net price
Efficiency	2	156	$8.1	5	235	$16.6	$13.2
PV Solar*	7	489	$24.2	8	456	$21.6	$23.3
BUG	1	100	$130.0	2	600	$45.0	$57.1
DR	1	250	$66.5	1	250	$57.7	$62.1
Battery**	5	3,500	$76.2	6	2,500	$72.8	$74.8
Total Available	**16**	**4,495**	**$68.9**	**22**	**4,041**	**$58.7**	**$64.1**

*The levelized cost for solar 20 years; 8% discount rate is used for all resources
**Only the largest battery bid by each provider is included

Following each RFP, GridSolar submitted an evaluation for all parties and the MPUC to review, as well as GridSolar's recommendation of which MRA resources to accept, based on its

108 Maine Micro Grid explained that the offered three-year NTA contract could not provide investors with certainty that the required six-year holding period for the federal Investment Tax Credit incentive would be satisfied.

assessment and balancing of costs, expected reliability and performance, and taking into account diversity requirements of the MPUC and emissions reduction goals.

In summary, the evaluation criteria considered were:

- **Cost:** because the Boothbay Pilot's initial three-year contract duration is substantially shorter than the useful life of the MRA resources, GridSolar measured costs in two ways: (1) on an annual revenue requirement basis, and (2) on an expected life levelized equivalent cost per kW-month for the full 10-year extended project term. The first method computed the revenue requirement for each MRA resource by multiplying the capacity rating by the bid price each year.[109] The second method computed the net present value of the annual bid price over the expected 10-year project life (20 years were used for solar PV) at an 8% discount rate and calculated the amount per kW-month, which results in the same net present value if held constant over the expected life. A summary of the costs per kW-month is shown above in Figure 38.
- **Reliability:** reliability was evaluated through dynamic capacity ratings assigned to each MRA resource based on the conditions applicable to Maine and accounted for periodic inspections and performance audits. In addition, for RFP II, GridSolar adjusted the expected total capacity downward for those solar PV bids without firm development contracts.[110]
- **Diversity:** GridSolar found that batteries were almost four times more expensive than fossil fuel-fired generators and "provided no specific reliability advantage."[111] However, to meet the MPUC requirement that the Boothbay Pilot examine each technology under actual conditions, GridSolar acquired the least cost battery option to be used in the Boothbay Pilot.[112]
- **Green House Gas ("GHG") Emissions:** the GHG emission criterion for fossil fuel-fired generators has not yet been invoked, as the only BUG resources to bid have been diesel-fueled non-renewable ones. In addition, until now GridSolar has not yet been able to establish a verifiable reduction in GHG emissions from the battery MRAs as compared to the diesel BUG. It is unclear from available documents what GridSolar is currently doing to address GHG emissions.

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[109] More detailed explanations of how the initial capacity rating for each NTA resource is determined can be found on Exhibit L of the original RFP available on GridSolar's website: <http://www.gridsolar.com/rfp.html>

[110] Note that capacity rating adjustments for solar PV is more of a feasibility criterion.

[111] GridSolar, LLC. Interim Report: Boothbay Sub-Region Smart Grid Reliability Pilot Project. March 4, 2014

[112] Essentially, the recommendation needed to keep in line with the MPUC's requirement to procure a minimum of 250 kW each of conservation and efficiency, demand response, renewable distributed generation, and back-up generation – so this served as a constraint on the evaluation process, rather than an optimization goal.

Results of the RFPs

Even though four criteria were used for evaluation, GridSolar appears to have only considered the lowest cost for each technology type of MRAs when making its final recommendation. Diversity was mandated in the MPUC Order, and the MPUC actually set how much of each MRA resource would be procured. The GHG emissions criterion is not yet an active criterion because of the diesel BUG. After eliminating the high bids, the final selection of MRAs under the Boothbay Pilot resulted in nearly 350 kW of energy efficiency projects, 276 kW of solar, 500 kW each of BUG and battery, and 250 kW of demand response, as shown in Figure 39.

Figure 39. Combined RFP I and II Selected MRA Resources

	kW Procured				Weighted 3 yr price ($/kW-month)	Weighted 10 yr levelized price ($/kW-month)
	RFP I	RFP II	Total	% of Total		
Battery	0	500	500	27%	$164	$76
BUG (same)	500	500	500	27%	$17	$21
Demand Response	0	250	250	13%	$110	$58
Energy Efficiency	237	111	348	19%	$24	$10
Solar PV	169	107	276	15%	$46	$13
TOTAL	**906**	**1,468**	**1,874**			

Source: GridSolar, LLC. *Interim Report: Boothbay Sub-Region Smart Grid Reliability Pilot Project*. March 4, 2014

GridSolar projected that the MRAs selected in place of transmission in the Boothbay project (shown in Figure 42) will provide approximately $17.6 million in savings to CMP's ratepayers over the 10-year extended life of the project when measured against a traditional transmission-only solution.[113] It is important to note that these savings were quantified based on the cost savings relative to the required transmission-only solution over the 10-year life. In other words, the "savings" of the selected MRAs were determined by simply comparing the annual revenue requirements of transmission and MRA solutions, without any quantification of benefits.[114] The result of the comparison is shown in below in Figure 40.

Other quantifiable benefits could have been included in the study – for example, production costs savings, varying levels of reliability and uncertainty, environmental costs and benefits, as well as economic effects on the local businesses. To the last point, the Boothbay Interim Report

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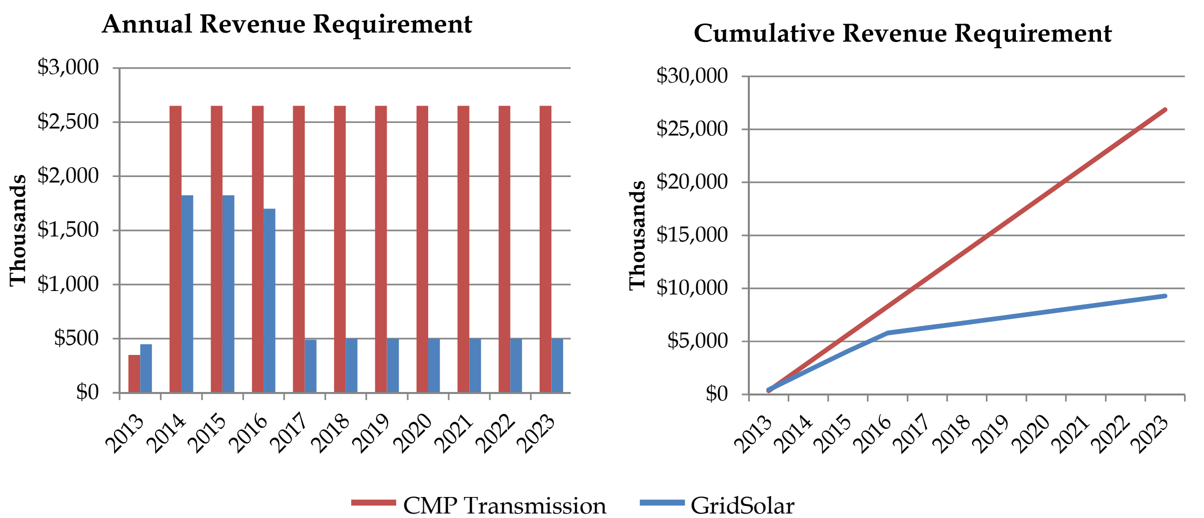
[113] It is important to note that the MRA solution still required about $2 million of incremental transmission investment to integrate the MRAs with the grid.

[114] The annual revenue requirement takes the total cost of RFP I, RFP II, and administrative costs of the projected 10-year life of the Boothbay Pilot. Where applicable, adjustments were made for actual and expected capacity achieved rather than contracted capacity. The BUG costs include $100,000 as the estimated up-front expense and 2013 lease fees associated with installation and interconnection of the 500 kW diesel BUG. The estimate of GridSolar's administrative cost assumes no further MRA projects are pursued in other parts of Maine.

acknowledged that the benefits-side of the evaluation was not comprehensive, noting that GridSolar has not asked its MRA providers to calculate the numbers of jobs created for each project, and that the Boothbay Pilot has likely resulted in fewer short-term construction jobs than the transmission-only solution.

Figure 40. Price comparison of all bids received in RFP I and II



Source: GridSolar, LLC. *Interim Report: Boothbay Sub-Region Smart Grid Reliability Pilot Project*. March 4, 2014

Observations

The Boothbay Pilot demonstrated that MRA resources may be available at reasonable cost in Maine to meet very specific and very local needs (that is, at a scale that is well suited for local needs and small investments). As a result of the Boothbay Pilot, GridSolar has recommended that the MPUC expand the MRA program in other regions of the CMP and Emera Maine electric grids. Notably, the consideration of MRAs as part of each new transmission project is now a legal requirement pursuant to Maine's transmission planning standards. However, in our view, the Boothbay Pilot exemplified some of the analytical issues with MRA evaluation and deployment:

GridSolar's experience demonstrates the ***need for a smart grid coordinator*** with the capacity and legal authority to develop, submit, implement, and operate MRA solutions in a manner that can meet grid reliability mandates. ***Deploying MRAs to address certain identified reliability needs may result in other reliability challenges***. For example, the project needed to secure diesel BUG to address certain reliability concerns that arose from deploying the MRAs. This ultimately leads to questions about whether the MRAs can themselves meet the technical "needs". It also highlights the questionable nature of scaling up the use of MRAs for larger identified "needs".

It is important to ***consider the magnitude of the need to be addressed***. As we discussed in Chapter 1, some MRAs can be useful in impacting micro- or local area needs (for example, energy efficiency or distributed generation may be useful in addressing localized transmission system weaknesses or relieving localized transmission system congestion). The MRAs selected in the Boothbay Pilot were relatively small in size and were solutions to a very local problem. Benefits of the MRAs were not investigated or quantified. However, given the nature of the MRAs, it is likely that the quantifiable economic benefits are also likely small and localized as compared than to transmission alternatives. If the transmission needs were of a bigger scale, there could be technical challenges in acquiring MRAs of comparable scale in the needed timeframe and at reasonable costs. Large scale MRAs may be difficult to deploy given inadequate infrastructure, grid coordination, and contingency resources that are readily available, among other challenges. That said, the lessons learned from the Boothbay Pilot, may not be directly transferrable to larger scale system "needs".

Some MRAs are still not cost competitive. For example, in the Boothbay Pilot, GridSolar found that batteries were four times as expensive as other solutions and provided no additional reliability benefits. While GridSolar anticipates the cost of MRA solutions to decline further as the distributed energy and efficiency market sector grows and technologies improve, this experience shows that some MRAs may not be cost effective solutions, and therefore costs need to be considered

Lastly, ***no comprehensive, full-scale benefit analysis was employed***. The decision to pursue MRAs was derived from a comparison of cost savings relative to the required transmission solution over the 10-year life (i.e., an avoided cost or least cost framework was employed). However, a decision based solely on costs of MRAs relative to transmission can be misleading. The fundamental basis of using the least cost framework is grounded in the assumption that MRAs and transmission projects provide the same benefits and have the same operating profile and characteristics. However, as we showed earlier in Chapter 1, MRAs and transmission provide different types of services and could create different benefits for customers, depending on the market circumstances and specific characteristics of the project. A more reasonable approach would be to compare the net benefits of the MRA and transmission solutions. In other words, a transmission project that has higher costs but also higher benefits would yield higher net benefits. Therefore, from an optimization perspective, a least cost analysis may be incomplete and biased. Benefits as well as costs need to be quantified and considered.

3.2 I-5 Corridor Reinforcement Transmission Project in Bonneville Power Administration

<u>Project Background</u>

The Bonneville Power Administration ("BPA") serves Idaho, Oregon, Washington, western Montana, and small parts of eastern Montana, California, Nevada, Utah and Wyoming. The I-5 Transmission Corridor is an important part of BPA's transmission infrastructure that connects load centers in Seattle and Portland with thermal and hydro generation located on the Upper Columbia River and British Columbia. During peak summer conditions, the I-5 experiences heavy power flow along the north-south route. In late 2008, BPA started to be concerned that summer peak load growth in and near Portland would exceed acceptable operational risk levels on one or more high voltage lines by as early as 2015. This could endanger lower voltage lines and associated equipment on this route, causing burnouts, equipment failure, and widespread system instability.

> **Agency/ entity responsible for decision-making and analysis**:
>
> - Bonneville Power Administration
>
> **Observations**:
>
> - The transmission solution was pursued to solve an identified reliability need
> - MRAs were shown to be economic solutions, however, the uncertainty and operating challenge around certain MRAs made them an infeasible solution to meet the reliability needs

At that time, the BPA used two systems to safeguard against overloading. First, a remedial action scheme ("RAS") would automatically drop up to 2,700 MW of generation capacity to reduce flows on the path in the event of an imminent outage. However, BPA was constrained in its ability to select the total amount of generation it could drop as part of RAS. BPA also had an operational response action plan called the South of Chehalis Sectionalizing Scheme ("SOCSS") that breaks the connection to lower voltage lines during an emergency, causing power to flow through an alternate path to reach Oregon. However, the large and rapid changes in power flow in the system caused by SOCSS were found to threaten overall system stability. BPA realized that both the RAS and SOCSS were not reliable, permanent solutions to the I-5 congestion problem.

In September 2009, BPA began considering a new 70 mile long 500 kV line to connect two new proposed substations in Castle Rock, Washington and Troutdale, Oregon. BPA's load flow studies indicated that the congestion problem on the I-5 corridor could be effectively solved by the proposed I-5 Corridor Reinforcement Transmission Project. BPA estimated that the direct costs (measured in 2010 constant dollars) associated with that transmission project would be $342 million, including $128 million for purchasing land. Furthermore, prior to 2006, BPA had constructed three new 500 kV lines and energized a 63 mile line from Central Washington to Yakima. These previous projects were now having a considerable impact on BPA's rate base and customer rates. In order to minimize further increases in customer rates, BPA started exploring deployment of MRAs that would allow it to then delay building new transmission in the I-5 corridor.

<u>Analytical framework and methodology</u>

BPA's MRA assessment included the following four steps:

Step 1: Estimate the extent of congestion

BPA estimated the current and projected flows over the existing network to assess the value and extent of future congestion and associated operational risk. BPA's forecast of flows was modeled by BPA Transmission Services ("BPA TS") and was based on demand growth estimates in greater Portland and Vancouver areas, which in turn were based on assumptions about economic growth and weather-related factors. BPA's existing network can be divided into three distinct parts. In order to transmit power from the generators to the load centers, BPA TS had to model power flows over each of these three parts to determine the extent of congestion. Figure 41 shows the path limits, BPA's forecasted flows on those paths and expected congestion for 2018 without the I-5 Corridor Reinforcement Transmission Project. BPA used this estimate to compare against available MRA options in order to determine the feasibility of implementing MRA. This process is detailed in Step 2 below.

Figure 41. BPA's estimate of MRA requirements

Path	Path Limit	BPA TS Modeled flow in 2018	Excess over path limit
Raver-Paul	1,450 MW	1,481 MW	31 MW
South of Napavine*	2,250 MW	2760 MW	510 MW
South of Allston	3,100 MW	3,397 MW	297 MW

* assumes continued use of SOCSS. Without SOCSS, this line's limit drops to 1,600 MW
Source: 'I-5 Corridor Reinforcement Non-Wires Alternatives Screening Study' report prepared for Bonneville Power Administration by Energy and Environmental Economics, Inc. January 12. 2011

Step 2: Quantify the portfolio of MRAs available

With the total excess flows established, BPA evaluated each component of MRAs to quantify its availability based on a benefit/cost screening criteria that only included MRA options with a benefit cost ratio of greater than 0.9.[115] The benefit cost ratio was designed to measure the benefit of a given MRA net of program cost. The considered cost-benefit analysis avoided supply and delivery costs, including deferred or avoided investments on the benefits side. Typical costs considered included payments made for equipment and incentives, paid for by both the utility and the end user. Importantly, BPA recognized that it was excluding positive externalities in its measure of benefits, for example, the benefits stemming from reduced emissions.

Based on the benefit/cost screening test, and available MRA options in the region, BPA identified four candidate options that were both available and passed the benefit/cost test:

1) Energy efficiency and other demand reduction measures

2) Demand response

3) New distributed generation

[115] 0.9 Benefit-cost ratio is in line with the specification provided by the Northwest Power Act of 1980, § 3(4) (D), 94 Stat. 2699. This section states ''estimated incremental system cost" of any conservation measure or resource shall not be treated greater than that of any non-conservation measure or resource unless the incremental system cost of such conservation measure or resource is in excess of 110 per centum of the incremental system cost of the nonconservation measure or resource.'(available at: http://www.nwcouncil.org/reports/poweract/)

4) Re-dispatch of existing generators

The following is a brief description of each qualified MRA option:

For energy efficiency and other demand reduction measures, BPA used estimates provided by the Northwest Power and Conservation Council ("NWPCC") in the 'Sixth Northwest Conservation and Electric Power Plan' document. These estimates were modified to make adjustments for the Bonneville region. BPA estimated that there would be a total of 143 MW of demand reduction (including energy efficiency) by 2020.

For demand response, BPA evaluated 17 different measures (potential demand response providers) for commercial, residential, and industrial customers. Of these 17 measures, 8 providers passed the screening criteria (i.e., benefit/cost ratio of greater than 0.9), including emergency and capacity market demand response for industrial and large commercial customers, peak time rebates for residential and small commercial customers, etc. The estimated total volume of demand response resources was estimated to be 16.3 MW in 2013 and was expected to reach 54.5 MW in 2020.

For new distributed generation, BPA considered 18 types of new distributed generation with various fuel types and sizes. The benefit-cost test included benefits such as power sales revenue, avoided capacity costs, avoided electricity purchase costs, and included both capital and operational costs. BPA assumed a 1% capacity factor for new distributed generation because the plants would only operate a few hours per year to meet the critical peak demand to reduce congestion load. Even allowing for the generators to operate additional hours to recoup revenues from the electricity market, it was unclear how much revenue these generators could actually make, given the conservative estimate of 1% capacity factor. The benefit/cost ratio test, combined with the conservative technical estimate, effectively excluded all plants smaller than 80 MW. Furthermore, it was considered unlikely that the Portland area could accommodate construction of larger plants, and therefore this MRA option was excluded from further consideration.

For re-dispatch of existing generators, BPA identified sets of existing generators in the north and the south end of the I-5 Corridor that would have to decrease or increase output to manage flows. The total volume of capacity possibly available for re-dispatch was estimated to be between 500 MW and 1,500 MW. However, BPA was unable to fully estimate the actual benefits, costs, or the volume of this category of MRA, because it would have required bilateral negotiations with generators to determine which of them will be willing to participate and at what cost.

Step 3: Estimate the time-frame for MRAs

BPA compared the cumulative volume of MRAs required (step 1) against its own estimate of MRA availability (step 2) to determine the number of years for which the identified MRAs could substitute for and delay the need for the Transmission Project. The estimates from Step 2 confirmed that energy efficiency and demand response options that had passed the 0.9 benefit/cost screening criteria alone would not be able to defer the need for transmission.

However, if BPA could enter into re-dispatch contracts with certain generators located north of the congested corridor to lower their output for limited hours during summer peak, and if it were feasible to replace this output with generation from the south of the congested network (using additional re-dispatch contracts), then it would be possible to use this portfolio of MRAs options (the energy efficiency and demand response options that passed the 0.9 benefit/cost screening criteria, as detailed in Step 2 combined with re-dispatch) to defer the transmission project for five years from 2015 to 2020.

Step 4: Evaluate net value of differing the transmission project (implementing MRAs)

BPA evaluated the net value of deferring the transmission project (implementing MRAs) for five years (2015 to 2020) as the sum of three different considerations:

- Present value of transmission revenue requirement ("TRR") savings due to deferral. TRR is estimated based on the total capital cost of the transmission project, as well as operations and maintenance costs and assumptions of WACC (7.69%) and inflation rates (2.2%). TRR does not include the potential revenue that the project could have earned from increased sale of firm transmission services to generators and other BPA customers.
- Present value of avoided cost of electricity and natural gas on account of increased energy efficiency as part of MRA. BPA used forecasts provided by NWPCC Sixth Power Plan for both the long term wholesale power price in the BPA region, as well as the long term natural gas commodity prices for the West of the Cascades region. BPA compared the cost of wholesale power for each time-of-use ("TOU") period[116] against the shape of the energy savings in that period to calculate the value of avoided cost of electricity. A similar analysis for estimating the avoided cost of natural gas would have required assumptions regarding the percentage of power generated by natural gas in that period, and the percentage of energy savings attributed to gas-based heating.
- Present value of avoided generation capacity on account of demand reduction and energy efficiency measures as part of the MRA solution. Since the Northwest has a large surplus of generation capacity will 2024, the present value of avoided generation capacity due to MRAs is diminished. Accordingly, BPA estimated this value in two parts. In the short run (until 2024), the value is set equal to the annual fixed O&M cost of a new GE LM6000 gas-fired combustion turbine. In the long run (after 2024), the value is calculated as the residual capacity cost of a new GE LM6000.[117] For demand response,

[116] NWPCC forecasts wholesale electricity costs over a 30 year horizon for each of the nine TAU periods, which include peak, off-peak and shoulder prices for summer, winter and spring.

[117] This methodology is a commonly accepted proxy used for the cost of generation capacity. The annualized fixed cost, less any revenue that a new combustion turbine can earn through operations in the local energy markets is also known as the Cost of New Energy (CONE). See MISO presentation on CONE for more information (https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/RECBTF/2013/20130919/20130919%20RECBTF%20Item%2002%20CONE%20Calculation.pdf)

the capacity value of avoided generation was assumed to be 100% of the total estimated kilowatts of demand response since demand response is considered very flexible and all of it can be safely assumed to be available when called upon. In contrast, for energy efficiency, the capacity value of avoided generation was based on the representative end-use load shape which was used to measure peak impact for each energy efficiency intervention.

Results of the analysis

Figure 42 shows the results of the TRR savings. For example, if the transmission project is deferred by one year to 2016, Bonneville ratepayers would save $17.8 million, or $52/kW of reduction at load center (which is needed to enable transmission project deferral).

Figure 42. TRR Savings from deferring the transmission project

	2015	2016	2017	2018
TRR Savings ($m)	$17.8	$34.6	$65.8	$93.9
$/kW	$52.0	$63.0	$69.0	$78.0
$/kW-year (levelized)	$52.0	$32.0	$18.0	$14.0

Source: 'I-5 Corridor Reinforcement Non-Wires Alternatives Screening Study' report prepared for Bonneville Power Administration by Energy and Environmental Economics, Inc. January 12. 2011

In addition to the TRR savings, Figure 43 shows the net present value of the avoided cost of electricity, natural gas, and generation capacity (collectively referred to as Total Resource Cost) according to the methodology outlined in the previous section. In addition to the total resource cost test, BPA also evaluated feasible MRAs from two more perspectives:

- Participant Cost, which measures the lifecycle cost for a participating customer who implements energy efficiency and/or demand reduction as part of the MRA solution. In general, the participant cost measures the net benefits to the participants (customers) who implement energy efficiency or curtail demand as part of demand response. Typical costs include incremental costs of installing and operating energy efficient alternatives and costs (financial or economic) associated with reducing demand. Typical benefits include incentives paid to participants for demand response, or savings in energy bill or any other incentives paid to participants[118]. A high benefit/cost ratio under this measure is a good indicator of the level of acceptance these proposed measures might receive.

- Societal Cost, which includes environmental externalities in addition to the total resource cost. In general, societal cost measures the net benefit associated with MRAs,

[118] See Environmental Protection Agency's 'Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers' handbook for more details. Available at: http://www.epa.gov/cleanenergy/documents/suca/cost-effectiveness.pdf

without defining who accrues those benefits or costs. For its purposes, BPA only included the net benefits from reduced air emissions, which were added to the Total Resource Cost to arrive at Societal Cost. The costs associated with environmental externalities include long term damage cost from climate change and costs related to decarbonizing electricity.

Figure 43. Net present value of avoided cost of electricity, natural gas and generation capacity

	Total Benefits ($m)	Total Costs ($m)	Net Benefits ($m)	Benefit-cost ratio
Total Resource Cost	$871.2	$448.2	$423.0	1.9
Participant Cost	$991.3	$325.3	$666.1	3.1
Societal Cost	$1,123.8	$456.1	$667.7	2.5

Source: 'I-5 Corridor Reinforcement Non-Wires Alternatives Screening Study' report prepared for Bonneville Power Administration by Energy and Environmental Economics, Inc. January 12. 2011

As can be inferred from Figure 43, the BPA concluded that the benefits of MRAs exceeded their costs, especially for individual participants in the MRA solution. However, the economic benefit-cost assessment was not the only criteria for judging the suitability of MRAs. Proposed MRA solutions were required to: (1) address forecasted congestion by reducing flows on the system, and (2) include some flexibility - be robust enough to withstand changes and deviation from initial assumptions (e.g., greater than anticipated summer demand, or lower than expected re-dispatch volumes). On both these counts, using MRAs to defer or replace the transmission project was considered extremely risky by BPA. This is because a significant part of the MRA solution consists of re-dispatch contracts with participating generators. These re-dispatch contracts must be individually negotiated between BPA and interested generators before the actual amount or re-dispatch quantity can be determined for MRA. Without guaranteed generator re-dispatch ability, the MRA cannot achieve the required reduction in transmission flows to prevent critical congestion and allow deferring the Project.

Considering that additional transmission capacity has to be made available by summer 2015, (either through the transmission project or by reducing congestion via MRAs), BPA decided in 2011 to proceed with the transmission project, while continuing as well with limited MRA implementation. This decision was considered necessary because BPA could not accurately estimate the time required to negotiate enough re-dispatch contracts. At the same time, deferring transmission project construction any later than 2011 would have made it extremely difficult to finish the transmission project by 2015, should MRAs prove to be insufficient.

Even though MRAs were unable to replace or delay the I-5 Corridor Reinforcement Transmission project, BPA decided to continue supporting energy efficiency and demand response. BPA recognized that investing in energy efficiency and demand response will increase net benefits associated with these measures and would also simultaneously reduce the requirements for generator re-dispatch contracts, which in turn would increase the likelihood that system conditions are primed for implementing additional MRAs in future, when and if needed.

<u>Observations</u>

The BPA experience shows that MRAs have the potential to be cost-effective solutions to identified reliability needs. However, the BPA experience (and its final decision to proceed with a transmission solution) highlights some of the challenges in relying on MRAs to address reliability solutions. While MRAs were a potential option for BPA to delay the transmission investment on the basis of an economic-only perspective, the extremely aggressive time-frame (2010-2015), ***uncertainties regarding cost and time*** required to negotiate bilateral re-dispatch contracts with generators, and the very ***narrow margin of excess quantity offered*** (no extra MRA capacity of demand or energy efficiency projections change) made it extremely risky for BPA to consider it as a stand-alone alternative to the transmission project.

Furthermore, the ***uncertainties around the operations of certain type of MRAs*** (i.e., re-dispatch of existing generators) were not modeled or evaluated in the analysis. A more comprehensive analysis should quantify and consider such uncertainties.

The BPA experience also highlights the ***complementary relationship between transmission and MRAs***. While the transmission solution was required to meet the identified needs of the system, BPA also provided support to MRAs such as demand response and energy efficiency. BPA recognized the benefits of investing in these resources along with transmission to increase the net benefit to the system and customers.

3.3 PATH and MAPP in PJM

Potomac-Appalachian Transmission Highline ("PATH") and Mid-Atlantic Power Pathway ("MAPP") were baseline system upgrades both first identified in PJM's 2007 Regional Transmission Expansion Plan ("RTEP") process.

<u>Potomac-Appalachian Transmission Highline ("PATH")</u>

PATH was a proposed 765 kV transmission line from the Amos Substation near St. Albans, West Virginia to the Kemptown Substation southwest of New Market, Maryland, including construction of the Kemptown Substation, and modifications to the Amos and Beddington Substations.[119] PATH was proposed in 2007 with an estimated cost of $ 1.8 billion.[120]

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119 On October 18, 2007, the Commission issued an order accepting PJM's revised tariff sheets (and cost allocation report) and for PJM Tariff Schedule 12 which included the baseline upgrades comprising the Original Configuration. *PJM Interconnection, LLC*, 121 FERC ¶ 61,034 (2007).

120 PJM. *2007 Regional Transmission Expansion Plan Report*. (Feb. 27, 2008). p. 11. http://www.pjm.com/documents/reports/rtep-documents/2007-rtep.aspx

PATH was first studied by PJM in 2007 to deliver reliability to the region's transmission grid in 2012. In 2008, PJM deferred the inception of PATH based on a retool analysis of 2012 system conditions.[121] Retool analysis updates transmission plans each year by reevaluating them based on the changing assumptions. The retool analysis is also effective in identifying chronic system weakness when the same set of violations to NERC Reliability Standard appears in successive period. PJM then knows a meaningful solution needs to be in place. The retool analysis used a lower load forecast for PJM, brought on by the downturn in the U.S. economy. Consequently, the PATH project was deferred to June 1, 2013 as PJM did not expect reliability criteria violations to occur within the near term. However, PJM indicated that those reliability criteria violations were not far below their reliability limits, many of which were loaded to 95 percent or greater.[122]

Agency/ entity responsible for decision-making and analysis:

- PJM

Observations:

- Transmission projects were not pursued
- Ultimately, these projects were cancelled due to the demand reductions resulting from the recession, additional conventional generation and some demand response.
- No economic analysis was performed
- PJM's evaluation of transmission projects focused heavily on their compliance with NERC reliability standards
- If full cost-benefit analysis had been performed, it may have shown that building a transmission line would produce higher net benefits to the system, in addition to meeting the reliability standards

In 2009, PJM validated the need for PATH while deferring the project for one more year. PJM claimed that the deferral of the transmission project was driven by the lower short-term load forecast due to the U.S. economic recession and increased level of demand responses.[123] The baseline deliverability analysis suggested that there would be widespread thermal and reactive criteria violations in PJM in 2014 without the completion of the PATH project. PJM still considered PATH the best option against other alternatives to resolve potential reactive criteria violations.[124]

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[121] PJM. *2008 Regional Transmission Expansion Plan Report*. (Feb. 27, 2009). p. 67. http://www.pjm.com/documents/reports/rtep-documents/2008-rtep.aspx

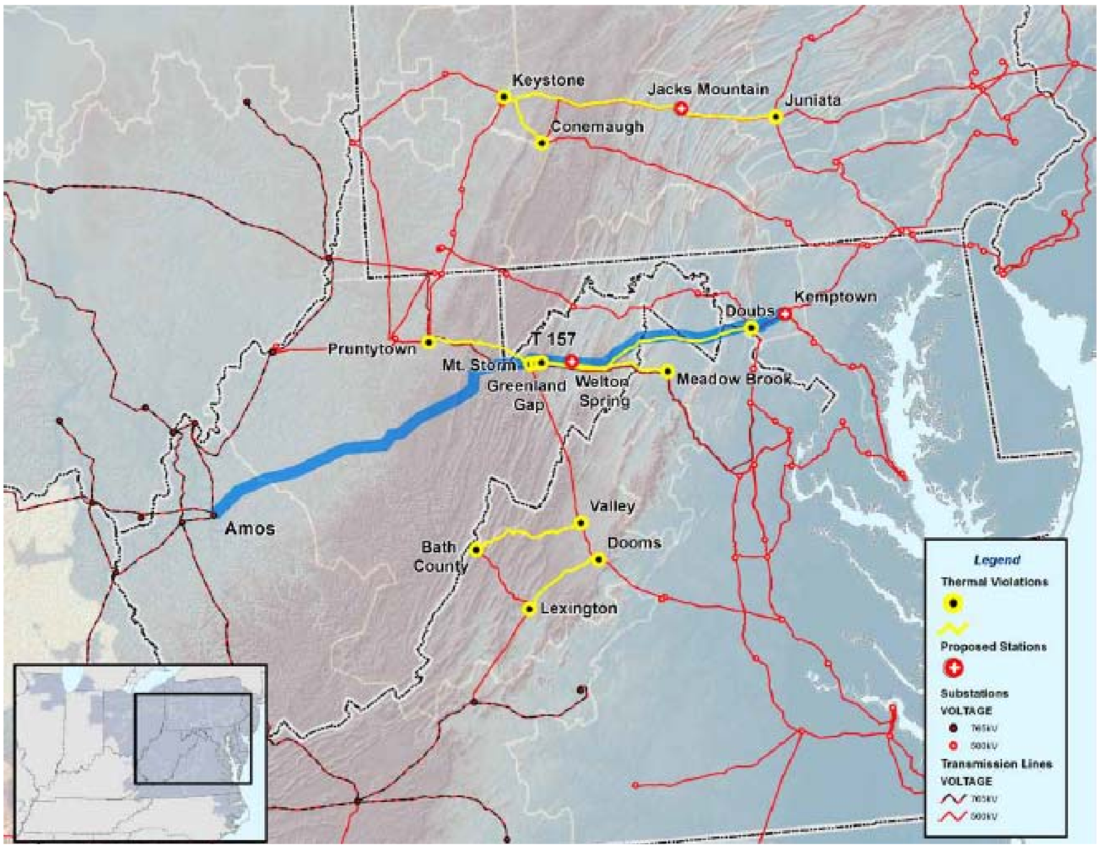
[122] Ibid. p. 67.

[123] FERC Docket ER12-2708. *Potomac-Appalachian Transmission Highline*. September 28, 2012. <http://www.pjm.com/~/media/documents/ferc/2012-filings/20120928-er12-2708-000.ashx>

[124] PJM. *2009 Regional Transmission Expansion Plan Report*. (Feb. 26, 2010). p. 81-82, 101-116. http://www.pjm.com/documents/reports/rtep-documents/2009-rtep.aspx

In 2010, PJM evaluated PATH against six alternatives and found PATH to be the "most effective, robust long-term solution" to provide transmission reliability and efficiency.[125] However it again deferred construction off PATH to June 2015.[126] In February 2011, PJM decided to put the PATH project on hold during the 2011 RTEP process. The decision was driven by the lower load growth, the increased commitment from DR, and the new generation entries.

Figure 44. Reliability Criteria Violations Driving Need for PATH



Source: 2010 RTEP Report

Finally, in December 2011, PJM conducted additional analysis by incorporating May 2012 Reliability Pricing Model ("RPM") base auction results.[127] The study suggested that the

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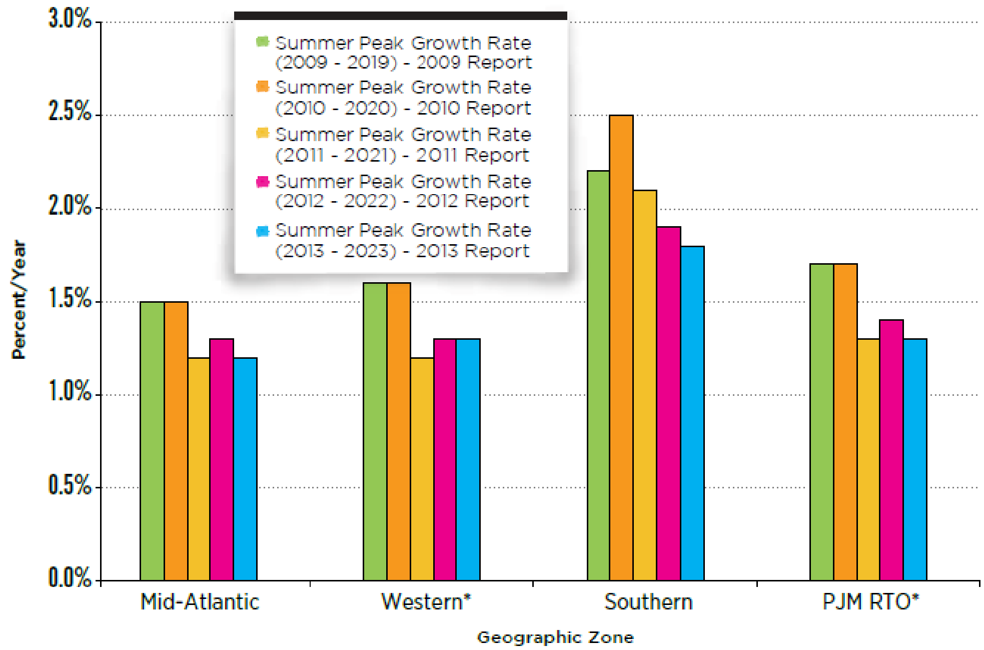
[125] PJM. *2010 Regional Transmission Expansion Plan Report*. (Feb. 28, 2011). p. 99-136. http://www.pjm.com/documents/reports/rtep-documents/2010-rtep.aspx

[126] Ibid. p. 91.

[127] PJM. *2011 Regional Transmission Expansion Plan Report*. (Feb. 28, 2012). p. 25. http://www.pjm.com/documents/reports/rtep-documents/2011-rtep.aspx

development of PATH to address the reliability needs in PJM was no longer valid due to lower load growth, increased market participation of DR resources, and new generation. On August 24, 2012, PJM reached the final decision to terminate the PATH project based primarily on the lower load demand forecast, as highlighted in Figure 45 (which is excerpted from the 2013 RTEP).[128]

Figure 45. 10-Year Summer Peak Load Sub-Regional Growth Rate Trends (2009-2013)



Source: 2013 RTEP Report

Mid-Atlantic Power Pathway ("MAPP")

MAPP is a 500 kV line that was originally designed to run from Possum Point substation in Virginia to the Salem station in New Jersey, with an estimated cost over $1 billion.[129] It was modeled in PJM's 2007 RTEP process to address the potential reliability criteria violations in 2012. The 2008 RTEP process recommended dropping the portion of the MAPP project from Maryland to New Jersey, so that the project would run from Possum Point substation in Virginia to Indian River in Maryland.[130] On August 18, 2011, PJM decided to hold MAPP in

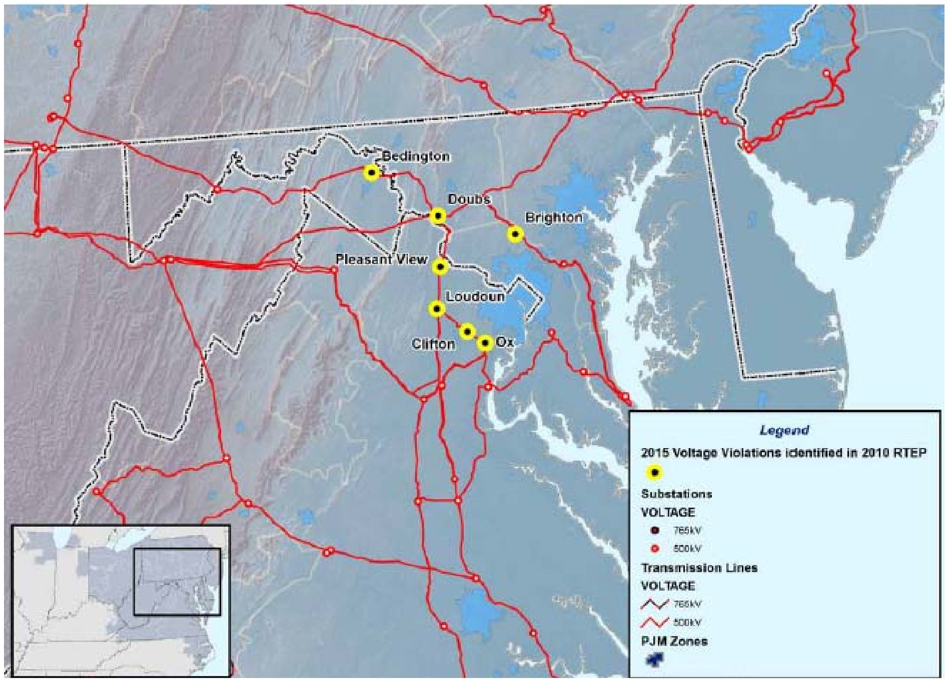
[128] PJM. *2013 Regional Transmission Expansion Plan Report. Book 2.* (Feb 2014). p. 22. http://www.pjm.com/documents/reports/rtep-documents/2013-rtep.aspx

[129] PJM . *2007 Regional Transmission Expansion Plan.* 2008. <http://www.pjm.com/~/media/documents/reports/2007-rtep/2007-section3b.ashx>

[130] PJM. *2008 Regional Transmission Expansion Plan.* 2009. <http://www.pjm.com/~/media/documents/reports/2008-rtep/2008-section5.ashx>

abeyance, deferring its on-line date to 2019-2021. PJM explained that the MAPP project was hold to address the potential reliability criteria violations in 2019-2021. However, on August 24, 2012, PJM decided to remove MAPP from the RTEP process due to more limited concerns over potential reliability criteria violations, which were the original driver for this project.

Figure 46. Voltage Violations (2015) Driving Need for MAPP



Source: 2010 RTEP Report

Observations

Both PATH and MAPP transmission projects were first proposed in PJM's 2007 RTEP process but later cancelled in the 2012 RETP process as a result of change in load forecast and other market supply conditions. The cancellation was primarily due to exogenous influences (lower demand growth due to an economic down turn) that impacted the assumptions PJM used to model its system needs. However, the experience highlights some key considerations that will be useful for developing our recommended set of analytical tools and techniques.

As part of the decision, PJM implicitly considered the impact of various MRAs such as energy efficiency, demand response, and new generation resources. In PJM, resources that have cleared PJM's capacity market produce firm commitments of new demand response, energy efficiency, and generating resources to meet the year forward projected load. The availability of these resources on a forward basis is then factored into future RTEP analyses. Moreover, because these resources are procured on a forward basis and committed for the relevant delivery year, in certain cases such as the PATH and MAPP, they have pre-empted the need for transmission solutions to ensure compliance with reliability criteria.[131]

However, EE and DR only commit for one year in PJM's RPM Base Residual Auction and the continuation of the EE/DR programs is highly uncertainly. Under adverse market conditions (i.e., low market prices), it is likely that some DR resources may exit the market. In our view, PJM failed to thoroughly take into account the issue of ***uncertainty.*** A more comprehensive analysis of load growth and capacity market uncertainty may have more fully reflected the ***insurance value of transmission*** and precluded the cancellation of the transmission projects.

Lastly, PJM's evaluation of the transmission projects focused heavily on their compliance with NERC reliability standards.[132] Other benefits such as production cost saving and market efficiency are studied but not emphasized. In addition, many other benefits of transmission are not estimated as part of PJM's current planning procedures. If a comprehensive economic analysis were performed, the transmission projects may have been shown to be economically net beneficial projects. ***A comprehensive analysis of the full range of benefits provided by a project should be considered when evaluating transmission projects***.

3.4 Tehachapi Renewable Transmission Project in California

<u>Project Background</u>

The unique geography of the Tehachapi area makes it one of California's leading resource areas for wind energy.[133] However, there has been historically limited transmission in the region to interconnect and bring the wind energy to market. In 2004, recognizing untapped potential in the Tehachapi area in response to the adoption of California's RPS goals, the CPUC established the Tehachapi Collaborative Study Group to develop a comprehensive plan for the expansion of transmission capability in the Tehachapi area. Following reports

Agency/ entity responsible for decision-making and analysis:

- California Public Utilities Commission

Observations:

- Transmission projects were driven by public policy goals
- No economic analysis was performed
- If full cost-benefit analysis were performed, a larger transmission project could have been built to spur more generation investments and maximize the positive externality

[131] PJM is in the process of moving away from its traditional "bright-line" baseline analysis for projects toward a scenario based approach that will allow for incorporation of a broader set of considerations, including public policy.

[132] In the RTEP analysis, a wide range of technical analyses are conducted to ensure that the system meets NERC Reliability Standard and there is no reliability criteria violation.

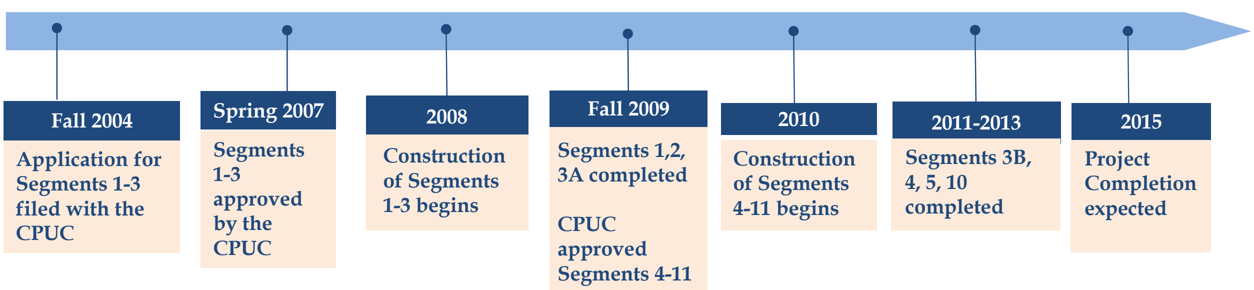
[133] *SCE. "The Tehachapi Renewable Transmission Project: Greening the Grid - Celebrating California's Progress in Renewable Energy." March 2010.*

issued by the study group in 2005 and 2006, the CPUC facilitated an agreement between SCE and CAISO on a work plan to provide for the orderly, rational, and cost-effective construction of Tehachapi project facilities.[134] As a result, the Tehachapi Renewable Transmission Project ("TRTP") was developed by SCE to provide market access to the expected development of up to 4,500 MW of wind-generation in this locality, and to deliver the wind energy to load centers in Los Angeles and San Bernardino counties.

Figure 47. Tehachapi Wind Resource Region

Source: Third party commercial database

Figure 48. Timeline of the TRTP



Source: SCE. *"The Tehachapi Renewable Transmission Project: Greening the Grid - Celebrating California's Progress in Renewable Energy."* March 2010.

TRTP has eleven (11) segments. SCE filed for approval of the TRTP with the CPUC in three separate applications – Segment 1 was approved on March 1, 2007 pursuant to CPUC Decision (D.) 07-03-012, and Segments 2 and 3 were approved on March 15, 2007 pursuant to CPUC

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[134] *SCE. "The Tehachapi Renewable Transmission Project: Greening the Grid - Celebrating California's Progress in Renewable Energy." March 2010.*

decision D.07-03-045.[135] Collectively, Segments 1-3 are known as the Antelope Transmission Project, which was completed in 2009. Segments 4 to 11 were approved in November 2009 and are expected to be completed by 2015.

TRTP is the first major transmission project in California being constructed specifically to access multiple renewable generators in a remote, renewable-rich resource area, with the intention of enabling utilities in California to reduce greenhouse gas emissions and comply with the state's ambitious RPS of having 33% of the state's electricity retail sales met by renewable resources by 2020.[136] In essence, TRTP is an example of a transmission investment serving as a complement to, and in fact a catalyst for, new generation.

Analytical framework and methodology

LEI notes that CAISO's transmission planning process was significantly overhauled in 2010 (after the TRTP project planning was complete), and therefore the process described herein for TRTP is not reflective of the current process. Nevertheless, certain aspects of the process remain (for example, the Transmission Economic Assessment Methodology), which can be used to highlight some key observations about how MRAs have previously been considered by system planners. According to CAISO's Transmission Economic Assessment Methodology ("TEAM"), a proposed transmission project is typically approved to be built if there is a proven reliability or economic need for the project. However, transmission projects that facilitate achieving the state's RPS goals are held to a different standard of need than other transmission projects. Specifically, CPCN applications for transmission facilities developed with the express purpose of facilitating achievement of the RPS goals are considered necessary.[137]

For Segments 1 to 3 of TRTP, CAISO determined that the project was needed to access a concentrated renewable resource area (CAISO recognized that the Tehachapi area offers the largest potential for wind-based energy production in California). CAISO also noted that there was interest from both utilities and merchant providers aspiring to develop projects there.[138] CAISO's assessment process generally follows two phases: technical assessment and economic assessment. Under its transmission planning methodology, CAISO typically assesses a

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135 CPUC. *Decision Granting a Certificate of Public Convenience and Necessity for the Tehachapi Renewable Transmission Project (Segments 4-11).* November 3, 2009. P. 2.

136 CPUC website. "California Renewables Portfolio Standard (RPS)." <http://www.cpuc.ca.gov/PUC/energy/Renewables/>. Last accessed on June 16, 2014.

137 Section 399.2.5(a) of the California Public Utilities Code ("Section 399.2.5") states that applications for a CPCN for new transmission facilities "shall be deemed necessary to the provision of electrical service for purposes of any determination made under §1003 if the Commission finds that the new facility is necessary to facilitate achievement of the renewable power goals established" in the RPS regulations. Public Utilities Code Section 399-399.9. Available at: <http://www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=00001-01000&file=399-399.9>. Last accessed on June 17, 2014.

138 CPUC. *Opinion Granting a Certificate of Public Convenience and Necessity (Decision 07-03-012).* March 1, 2007.

proposed project's reliability on a regional basis[139] to ensure that (1) the identified reliability problem that is to be solved by the project does exist; (2) the identified reliability problem is actually solved by the project; (3) determine that no other serious reliability issues are created by the project; and (4) account for other reliability improvements due to the project.[140] In this regard, it was determined that TRTP would address the reliability needs of the CAISO grid due to projected load growth in Antelope Valley area and to address South of Lugo transmission constraints – an ongoing source of reliability concern for the Los Angeles Basin.[141]

With respect to economic assessment, CAISO typically determines if the economic benefits of the project over its lifetime for CAISO ratepayers exceed the cost of the project to ratepayers. Economic benefits typically have two main components: (1) energy benefits; and (2) locational capacity requirement benefits. Energy benefits are quantified as the reduction in the CAISO ratepayer's energy payment due to the transmission project while locational capacity requirement benefits are quantified as the reduction in payment by the CAISO ratepayers for meeting local capacity needs due to the transmission project. In the case of TRTP, CAISO pointed to the "societal benefits stemming from lower natural gas costs" arising due to a potential reduction in fuel consumption by natural gas generators displaced by the wind generation in Tehachapi.[142] Moreover, CAISO verified that the TRTP is the least cost solution to solving the identified reliability problem by reviewing five other (transmission) project alternatives to TRTP. However, while CAISO considered the reliability and economic benefits of the project, it did not rely on these benefits to justify the approval of the TRTP.[143] In essence, the Tehachapi project saw the "most restrictive" application of CAISO's TEAM as the relatively low cost of the wind resource being accessed meant that the study could be framed as a "cost-effectiveness study (how best to access a resource that would be developed in any case), without having to consider generation alternatives."[144] In essence, CAISO did not subject the TRTP project to the full extent of TEAM given that the project would help California achieve its

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139 CAISO studied the TRTP together with the Sun Path project and the LEAPS project according to their initial plan of service in order to assess their individual reliability and economic values as well as to evaluate their interactions with one another.

140 CAISO. *CAISO South Regional Transmission Plan for 2006 (Presentation at California Energy Commission)*. August 15, 2006. P. 24.

141 CAISO. "South Regional Transmission Plan for 2006 – Part II: Findings and Recommendations on the Tehachapi Transmission Project." P. 4. Available at: <http://www.caiso.com/1b6b/1b6bb5ea7ad0.pdf>

142 CAISO. "South Regional Transmission Plan for 2006 – Part II: Findings and Recommendations on the Tehachapi Transmission Project." P. 9. Available at: <http://www.caiso.com/1b6b/1b6bb5ea7ad0.pdf>

143 CAISO. *Memorandum to the ISO Board of Governors*. January 18, 2007. P. 8.

144 Xiao-Ping Zhang. "Restructured Electric Power Systems – Analysis of Electricity Markets with Equilibrium Models." IEEE Press Series on Power Engineering. July 2010. Chapter 7, "Economic Assessment of Transmission Upgrades: Application of the California ISO Approach," M. Awad (CAISO) et al.

RPS goals, and focused its analysis on choosing the most cost-effective transmission design for the project.

<u>Results of the analysis</u>

The CAISO Board of Governors approved the TRTP as it was expected to bring the following benefits to the CAISO power market:[145]

- it is the ***least-cost solution*** that reliably interconnects more than 4,000 MW of generating resources in Tehachapi Area Generation Queue;
- it ***addresses reliability needs*** of the CAISO grid due to projected load growth in Antelope Valley area as well as helping to address South of Lugo transmission constraints;
- it ***facilitates the ability of utilities in California to comply with the RPS*** by providing access to planned renewable resources in the Tehachapi Wind Resource Area;
- it is ***expected to provide economic benefits*** to the CAISO ratepayers by providing access to wind and other efficient generating resources under development;
- it ***makes it possible to expand the transfer capability of Path 26*** in the near future with a low cost upgrade of PG&E's portion of the Midway-Vincent Line No. 3 line; and
- it ***lays the groundwork for the integration of large amounts of planned geothermal, solar, and wind generation*** in Inyo and northern San Bernardino counties.

Following CAISO's approval, CPUC approved segments 1 to 3 of TRTP in March 2007 and segments 4 to 11 of TRTP in November 2009. According to CPUC's decision approving the first three segments of the TRTP, a precedent was set for what the CAISO would be required to show in future transmission applications that are meeting policy goals. Specifically, CAISO would be required to show that a proposed project passes a three-prong test to be able confirm the policy need for the project: "(i) that a project would bring to the grid renewable generation that would remain otherwise unavailable, (ii) that the area within the line's reach would play a critical role in meeting the RPS goals, and (iii) that the cost of the line is appropriately balanced against the certainty of the line's contribution to economically rational RPS compliance."[146] CAISO was required to apply this test to segments 4 to 11 of TRTP. These other segments passed the three-prong test and the CPUC then determined that these transmission investments would be necessary to achieve the state's RPS goals. As a result, further consideration of need based upon reliability or economic factors was deemed unnecessary and the CAISO did not

[145] CAISO. *Memorandum to the ISO Board of Governors*. January 18, 2007. PP. 1-2.

[146] CPUC. *Opinion Granting a Certificate of Public Convenience and Necessity (Decision 07-03-012).* March 1, 2007.

perform studies that would have quantified the complementarity between transmission and future MRAs (generation).[147]

CPUC also approved a "backstop" cost mechanism allowing SCE to recover through retail rates any costs of the TRTP project as long as the costs are under the price cap set by the CPUC, regardless of whether or not the costs are approved by the FERC for recovery through transmission rates. The CPUC can allow prudently-incurred costs of a transmission project not approved for recovery in general transmission rates by FERC to be recovered in CPUC-jurisdictional rates, if the new transmission project facilitates RPS goals. CPUC set the cost cap at $257.6 million for the first three segments of the project[148] and approximately $1.5 billion for the rest of the project (excluding a $0.3 billion allowance for funds used during construction).[149]

The development of TRTP did indeed spur the renewable development in the remote region. Wind resources in Tehachapi region are in the process of being developed – by the last quarter of 2013 over 500 wind projects were either operating or under construction, representing total capacity of more than 1.5 GW.[150]

Observations

The TRTP provides a good example of the ***broad range of benefits that transmission can bring***. In this case, the TRTP was selected largely due its public policy benefit – the new transmission line was estimated to allow for the delivery of 4,500 MW of renewable (wind) energy to the market, helping California meet its aggressive RPS goals.

However, when determining the decisions to move forward with the TRTP, CAISO did not qualitatively evaluate the ***complementary benefits of the transmission line to motivate new generation***. To fully utilize the transmission infrastructure, the CAISO Board and CPUC should have conducted a thorough analysis to quantify broader benefits such as the compliance benefits of meeting public policies, like RPS goals or carbon reductions. Had the full range of benefits been considered, it is possible that more transmission investments may have been appropriate, and that the complementarity between transmission and generation would have spurred additional wind developments in the wind abundant regions, which may have created further benefits to customers.

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147 CPUC. *Decision Granting a Certificate of Public Convenience and Necessity for the Tehachapi Renewable Transmission Project (Segments 4-11).* November 3, 2009. P. 8.

148 Foster Electric Staff. "CPUC approves two more parts of SoCal Edison's $1.8 billion Tehachapi transmission project." *SNL Financial*. March 21, 2007.

149 CPUC. *Decision Granting a Certificate of Public Convenience and Necessity for the Tehachapi Renewable Transmission Project (Segments 4-11).* November 3, 2009. P. 1.

150 Matthew Martz. "Wind farms generate more than electricity for Kern." Tehachapi News. September 24, 2013. Available at: <http://www.tehachapinews.com/news/local/x196571163/Wind-farms-generate-more-than-electricity-for-Kern>. Last accessed on June 19, 2014.

CAISO has a long history of performing economic analysis and has experiences using the TEAM framework to analyze the economic benefits of a transmission project. CAISO should conduct the TEAM analysis even if a project is being built to meet reliability needs. Through the economic analysis, policy makers can determine what the optimal size of the transmission project would be to maximize the positive externality of an infrastructure investment.

Furthermore, ***given the long lead time nature of the transmission investments, they can open up opportunities for MRAs that were not obvious or hidden there before***. In addition to Tehachapi in California, there are examples of the complementarity between transmission and MRAs in other regions in the U.S. For example, transmission was used to promote the development of renewable resources in Texas.

3.5 Key Takeaways

The preceding case studies provided examples of how MRAs have been evaluated by system planners in recent years. Although there were a number of different MRA technologies considered, and the "need" driver behind the projects varied (for example, reliability and public policy) there are several observations from these case studies that can inform the development of a set of analytical tools and techniques for evaluating MRAs alongside transmission:

- ***Significant challenges exist in forecasting the operational characteristics of MRAs in the longer term and in considering the uncertainty of MRA operations***. The case study of the I-5 Corridor Reinforcement Transmission Project in BPA revealed the uncertainties regarding MRAs (for example, negotiating bilateral re-dispatch contracts with generators), which made MRAs less attractive from a feasibility and practicality perspective than transmission.

- More generally, in the case study documenting the events leading to the cancellation of PATH and MAPP in PJM, one can also observe the interplay of the ***uncertainty in market conditions*** (and the development of MRAs) and the decisions made in the course of transmission planning. In hindsight, with demand levels back to pre-2010 levels, the decision to cancel PATH and MAPP may have been premature. Furthermore, although both these projects were motivated by reliability concerns, they may have nevertheless been net-beneficial from a market efficiency and economics perspective; however, a comprehensive cost-benefit analysis was not performed.

- ***A robust cost-benefit analysis should measure and quantify these operational and market uncertainties.*** In the light of such uncertainties, the insurance value of a given solution may be quite significant.

- In some cases, a ***comprehensive economic analysis*** was not performed in consideration of transmission investment and MRAs. As such, certain benefits of transmission may have been overlooked. In the case of PATH and MAPP in PJM, even though both transmission projects were not needed for reliability reasons, they could have potentially brought significant net benefits if a full economic assessment had been performed. Economic analysis should not be a secondary consideration when evaluating an infrastructure investment. Rather, of the full range of benefits provided by a proposed investment (reliability, economic, environmental, etc.) would allow system planners and customers to maximize their benefits.

- ***MRAs and transmission are not equally providing all the same services and benefits will therefore differ – a more comprehensive (inclusive) analysis of benefits and costs should be undertaken in order to optimize planning decisions.*** System planning analysis often 'downgrades' the economic cost-benefit analysis or focuses solely on least-cost solutions.

- ***The ability of MRAs to consistently meet the technical (reliability) needs of the system are sometimes overlooked for the sake of policy – technical feasibility should be a requirement, not an option.*** In the Boothbay Pilot in Maine, even though MRAs were pursued, the Maine Public Utilities Commission needed to install a temporary 500 kW back-up diesel generator to meet the interim reliability need. This indicates that there may be technical challenges in acquiring MRAs to meet larger, regional needs at a reasonable cost.

- It is important to consider the ***flexibility and adaptability*** of a proposed MRA or transmission project– will it be robust enough to withstand changes and deviations in market conditions from initial assumptions (e.g., greater than anticipated summer demand, or lower than expected re-dispatch volumes). The case study of the I-5 Corridor Reinforcement Transmission Project in BPA demonstrated that MRAs may not be as robust as transmission solutions given the inflexible amount of available MRAs. Furthermore, the issue of uncertainty regarding the negotiating to re-dispatch with existing generators further magnifies the ***operating challenges*** of MRAs.

- In the case study of the Tehachapi Renewable Transmission Project in California, we find a situation that highlights the potential of strong ***complementarity*** between transmission and generation (a form of MRA) - in contrast to the common misconception that transmission and MRAs are always substitutes. Nonetheless, a full economic analysis was never conducted to assess this complementarity and the extent of the additional positive benefits arising from this positive externality between transmission and generation. Economic theory would suggest that in the face of a positive externality, we may not have enough investment – so perhaps if a comprehensive benefits analysis had been done, a decision would have been made to build even more transmission.

> A **positive externality** exists when an individual or firm making a decision does not receive the full benefit of the decision. The benefit to the individual or firm is less than the benefit to society.

Chapter 4: Suggested Analytical Tools and Techniques for Evaluating MRAs in the Transmission Planning Process

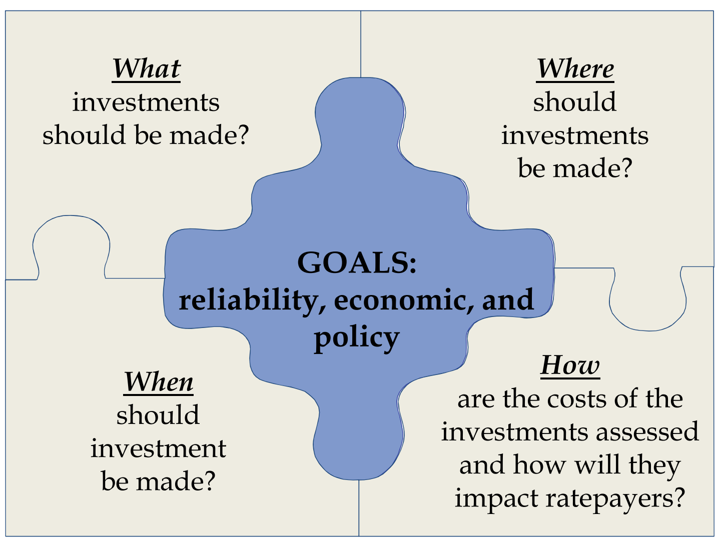
System planning is a complex process through which system planners work to develop and maintain a robust electric power system that addresses reliability, economic, and policy goals in an efficient and effective manner.

System planners have to tackle a number of critical questions:

- ***What*** investments should be made?
- ***Where*** should investments be made?
- ***When*** should investment be made?
- ***How*** are the costs of the investments assessed and how will they impact ratepayers?

These questions form the four cornerstones of the reliability and economic analysis required in system planning (see Figure 49). Although these questions sound simple enough, answering them to identify optimal investment choices in light of given system, market, or policy constraints is a challenging undertaking, made all the more complex by the fast evolution of market rules and technology in the electric power sector.

Figure 49. Cornerstones of system planning



As discussed in the Introduction of this Report, system planning has become increasing complex due to the decoupling of the transmission and generation investment decision through deregulation and market restructuring. In addition, technological advances that have given rise to an increasingly diverse set of potential options for meeting system needs. As the nature of system planning becomes more complex, the analytical tools and techniques used by system planners must also evolve. The analysis deployed by system planners should be inclusive, and consider all feasible solutions - transmission and MRAs. Furthermore, the analysis should be sufficiently detailed and comprehensive so as to distinguish between the feasible solutions' traits and defining characteristics, and benefits, as well as discern any relationships between possible solutions – be that relationships of substitutability or complementarity.

In this final chapter of the Report we describe a set of analytical tools that should be used with best practice techniques to evaluate MRAs and transmission on an equal footing. The economic analysis should be conducted within the discipline of cost-benefit framework as such a framework is flexible and adaptable to comprehensively consider benefits and costs, while also estimating the impact of uncertainty and the endogeneity of the investment decision.

We recognize that different RTOs already have customized approaches for system planning in place, so we do not recommend a specific ("one size fits all") process. Rather, we recommend a set of tools and analytical techniques that can be incorporated into existing processes. Our recommended tools and techniques are based upon lessons learned through our research of MRAs, transmission, and the services and benefits that each type of technology can provide, coupled with several guiding principles for developing an effective analytical process.

4.1 Guiding principles for a comprehensive framework

As discussed in the Introduction, with this Report, we are seeking to inform the development of a framework that more comprehensively and methodically helps system planners examine various solutions to multi-dimensional system "needs". An optimal system plan is a utopia. So rather than aim for utopia, we make recommendations on analytical tools and techniques that would result in **effective** system planning. The term "**effective**" is most apropos as it denotes a combined sense of the three key criteria such as efficiency, non-discrimination, and practicality.

> **Definition of *EFFECTIVE* –**
>
> 1) producing a decided, decisive, or desired effect
> 2) impressive, striking
> 3) ready for service or action
>
> *Source: Merriam-Webster Dictionary (Online Version)*

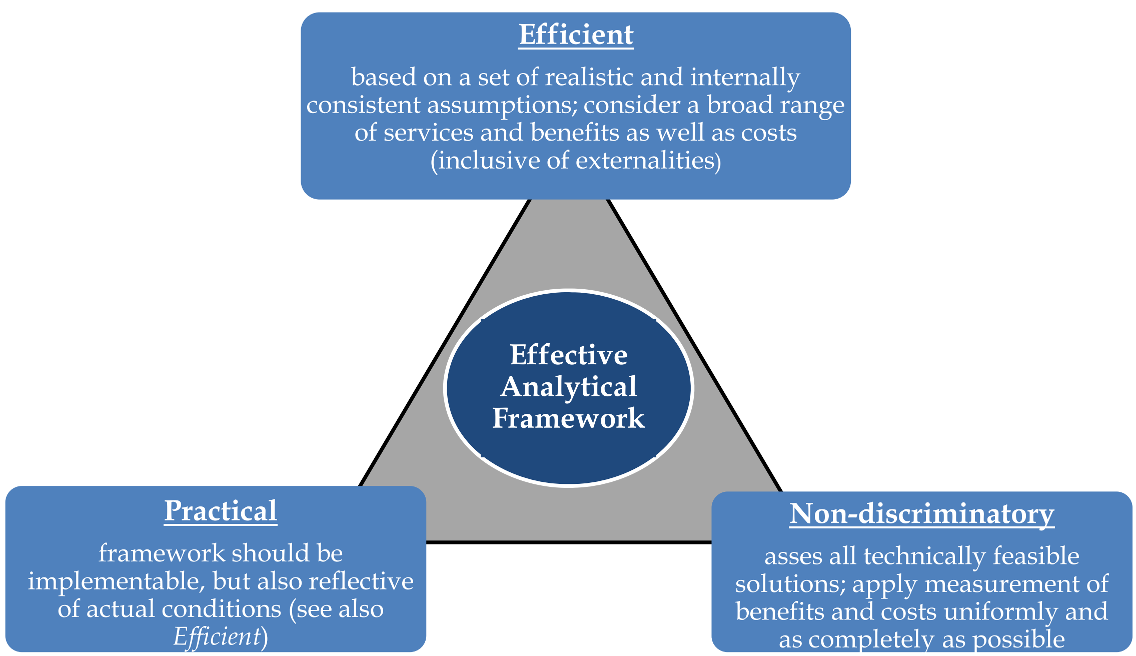
- ***Non-discriminatory***: the evaluation needs to study all technically feasible solutions. One cannot evaluate MRAs in isolation. The evaluation must be done in a way that MRAs and transmission are comparable and on equal footing in terms of both technical characteristics (reliability) and economic attributes (net benefits). But once the attributes and benefits are identified and measured, the analytical framework must be decisive. In our opinion, an effective, non-discriminatory analytical framework must combine consideration of technical issues, reliability, and economics, rather than just create artificial classifications and constrain analysis of investment to one or the other. We also need to recognize that under certain circumstances, MRAs and transmission are close substitutes, but they can also be complements. Therefore, the infrastructure investment (either transmission or MRAs) should aide the market development, and not obstruct it.

- ***Efficient***: Efficiency is also best epitomized through completeness. The evaluation tools and analytical techniques need to be able to address negative impacts (i.e., negative externalities) that transmission projects and MRAs could potentially have. Similarly, the evaluation framework should also include any positive impacts (i.e., positive externalities and welfare gains) that transmission projects and MRAs could potentially create. Similarly, through the consideration of "needs", and an accounting of direct, indirect impacts (such as local and regional macroeconomic benefits), the most efficient decisions are expected. Specifically, transmission projects may exhibit a variety of positive externalities and the framework needs to internalize and measure such externalities in the analysis in order to get the optimal level of investment or quantity of goods and services.

  In addition to completeness, the "toolkit" must be able to create cost-benefit analyses that are based on a set of realistic assumptions. Given that infrastructure investments are long-lived goods, the analysis framework should consider a relatively long period of time (10-20 years) instead of just one year whenever possible. It should also reflect an understanding of the range of plausible future market conditions. Transmission projects are planned through central coordinators while generation and other MRAs are no longer controlled by central coordinators. When incorporating MRAs into the multi-year analysis, one should reflect the dynamic market response. We need to analyze the risks private investors facing and rationalize the private investor's decision.

- ***Practical*:** The proposed "toolkit" should be implementable at a reasonable cost and using reasonable levels of effort.

Figure 50. Guiding principles of the framework



4.2 Lessons learned

Evaluating transmission projects and MRAs on an equal footing is no easy task. Transmission planning is mainly done through central coordinators while the investment decision for MRAs is not controlled by central coordinators. Therefore, in terms of economic analysis, this becomes a more complex planning problem as many agents are involved in this process and there is resulting uncertainty about the presence of MRAs in the future and other key drivers of system performance. One key to executing economic analysis of such a complex issue is to make sure the analytical approach (1) recognizes and considers the uncertainty, (2) anticipates rational response and dynamic behavior of market participants in the face of such uncertainty, and 3) comprehensively measures all benefits and costs, including positive and negative externalities.

In developing a recommended "toolkit" that would enable planners to evaluate MRAs alongside transmission, we took into considerations key observations about MRAs and transmission investment that we compiled from our prior work experiences and researching these case studies.

- ***Transmission provides a variety of services and offers a broad range of potential benefits.*** Understanding the types of services and benefits transmission can provide is necessary as MRAs will be evaluated in terms of the services and benefits they can provide when compared to transmission.

- ***An MRA generally only is able to provide a partial suite of services that transmission provides.*** From the review of MRAs in Chapter 1, we learned that MRAs differ from transmission in the terms of services provided. MRAs may provide some of the services that transmission can provide, but they cannot perfectly replace transmission. Furthermore, the services each MRA can provide vary.

- ***Relying on least cost analysis is not sufficient - comprehensively measuring the benefits and costs to customers is necessary in order to distinguish among the feasible solutions and the various services that each can provide***. In the analysis of MRA policies regionally, federal guidelines, and specific case studies involving MRAs, we have found that such a comprehensive analysis is rarely performed. In the case of PJM's retooling analysis of PATH and MAPP, and in the case of the Tehachapi project pursued by CAISO, an economic analysis was not performed as the investment decision was justified by reliability analysis or public policy edicts. In the Boothbay pilot project in Maine, the analysis focused primarily on costs. In other words, the least cost approach was employed without consideration of the different benefits (and/or lack thereof) of the various MRA investments, especially relative to the transmission-only solution. In the case of BPA's I-5 Corridor Reinforcement project, an economic analysis was performed, and it revealed that significant challenges exist in forecasting the operational characteristics of MRAs in the longer term and in considering the uncertainty of MRA operations. However, the uncertainty was not modeled directly in the analysis and the decision-maker ultimately overrode the results of the economic analysis. Furthermore, the transmission project was not modeled explicitly and the benefits of transmission project were not quantified. In other words, the potential externality was overlooked, i.e., transmission projects may spur more generation resources in the long term and may also serve to motivate more demand side resources.

- ***It is important to consider both the magnitude and breadth of benefits of MRAs compared to transmission.*** That is, it is important to consider the ability of a solution to provide benefits and services to various customer classes over a large geographic and time dimension. Some MRAs have been shown to provide benefits on a very limited and very local scale. Transmission on the other hand, is typically built to provide benefits to the larger regional system over a long period of time.

- ***A comprehensive analysis must include consideration of negative and positive externalities associated with potential costs and benefits.*** These externalities can be positive (i.e., benefits). For example, we have seen examples of the strong complementarity between transmission and some MRAs, where transmission leads and opens up further opportunities for MRAs. On the other hand, the externalities can be negative (i.e., costs), where MRAs require additional spending due to the nature of the services they provide and how they interact with other elements of the power system. For example, the Boothbay Pilot Project showed that incremental investments in backup generation were needed to maintain system reliability when MRAs were implemented.

- ***Operational uncertainty is an important consideration for MRAs.*** Given the technical and operational characteristics of transmission, system planners historically have not had to give significant weight to operational uncertainty in their analyses. However, we have found that there are often high levels of operational uncertainty associated with MRAs, especially in the longer term. Similar to externalities, this uncertainty could either be positive (benefit) or negative (cost). For example, there is also some uncertainty about how "useful" transmission will be in future given market trends. A comprehensive framework must therefore be able to value the optionality of transmission (for example, the ***insurance value*** of a selected transmission project to avoid future shortfall in local supply or in order to more reliably meet accelerated growth of electrical demand), while also considering the optionality of MRA solutions.

4.3 Recommended Analytical Tools and Techniques

The lessons learned and guiding principles lead us to six key precepts that should underpin the effective analysis of MRAs and transmission. These precepts are:

1) MRAs should be judged on the same criteria for reliability and economic benefits as proposed transmission

2) Technical feasibility should be a requirement, not an option; the ability of MRAs to consistently meet the technical (reliability) needs of the system are sometimes overlooked for the sake of policy3) The evaluation framework must assess a broad set of benefits and costs to fairly compare feasible investment options4) A robust cost-benefit analysis

should measure and quantify the uncertainties and risks associated with both MRAs and transmission - insurance value may be quite significant

5) MRAs and transmission are not equals in the services and benefits they provide – a more comprehensive (inclusive) analysis of various benefits should be undertaken in order to optimize planning decisions

6) Economic cost-benefit analysis should consider the dynamic evolution of the system, consistent with rational expectations. Such an analysis may show potential for complementarity between transmission and certain MRAs, which could justify the need for more investment.

A successful analytical framework, consistent with these precepts, should (1) identify all the benefits and costs and gather them under the umbrella of a cost-benefit analysis, (2) use the right set of tools to measure those benefits and costs, and (3) conduct analyses that specifically address the identified challenges for evaluating MRAs alongside transmission in an efficient manner. This means evaluating them technically to the same specified "needs" criteria, across the same categories of benefits, and over the appropriate geographical and time dimensions.

4.3.1 Cost-Benefit Analysis

Cost-benefit analysis ("CBA") is a method of evaluating the economics of a project or investment. The ultimate goal of CBA is to quantify all costs and benefits of a project or investment over its construction (if any) and operation periods. Given the different operating life of various projects, CBA often uses the net present value ("NPV") technique to bring all costs and benefits associated with a project over time back to a defined/standard year. In other words, a CBA can be used to analyze a specific project and also to compare across and select from multiple projects. Under a CBA, one compares the total benefits (gross benefits) of a project with its total costs to determine the net benefit of a project. Generally speaking, a project should be pursued if benefits exceed the costs (that is, if it had a positive net benefit).

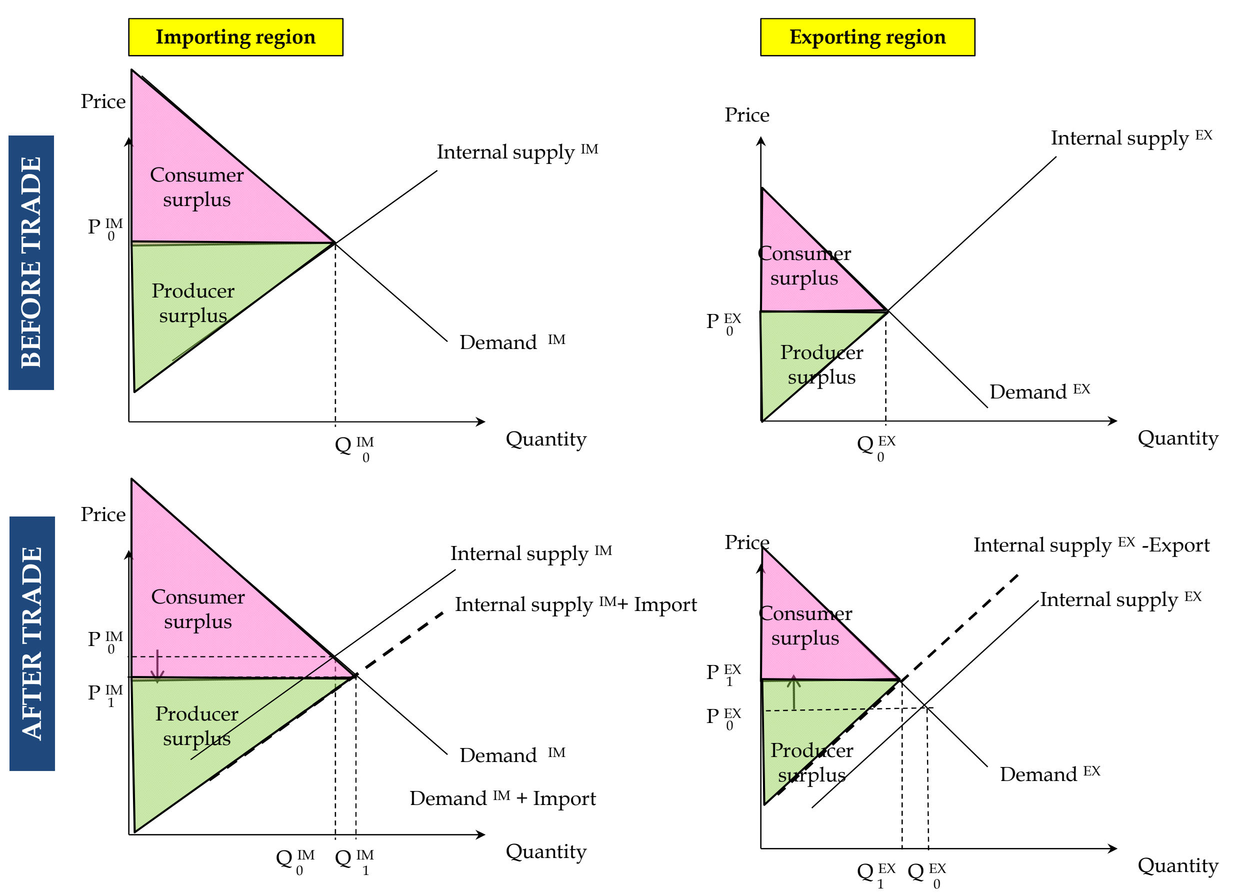
In the following sections, we will first discuss the benefit metrics, followed by the cost metrics that should be considered when performing a CBA. We will then conclude with a discussion of the selected parameters that should be considered when performing a CBA.

4.3.1.1 Benefit Metrics and Perspective

A CBA can be conducted from the perspective of the investor, from the perspective of customers, or society as a whole. In general, the costs and benefits should be aligned in terms of who they impact (i.e., the perspective). Therefore, we suggest that the analysis is done from the customers' perspective as they are the party who pays for the transmission investment and also from society's perspective to capture externalities. Two measurements are often used when referring to social benefits: economic surplus and efficiency gain. Economic surplus is mostly a transfer between customers and producers. On the other hand, the efficiency gain refers to the fact that the same amount of product is produced at a lower cost. In other words, the product is produced more efficiently.

Economic surplus refers to two related quantities: customer surplus and producer surplus (see Figure 51). Customer surplus is the monetary gain obtained by customers because they are able to purchase a product for a price that is less than the highest price that they would be willing to pay. Producer surplus is the amount that producers benefit by selling at a market price that is higher than the lowest price they would be willing to sell for. Figure 51 provides an example of how customer surplus and producer surplus can shift between two regions. In this example, we look at the shift between surpluses resulting from trade (or flow of power) between the regions. Before trade, the importing region has a higher price than the exporting region. With trade, the importing region's market price goes down. As a result of trade, customer surplus increases because they consume more at a lower price. The impact on producer surplus (for the region) is less certain, as the quantity produced increases but the price also decreases. The impact to producer surplus will depend on the elasticity of the supply curve of the importing region. The opposite impact occurs in the exporting region. Customer surplus decreases as customers consume a lower quantity of goods at a higher price. The impact of producer surplus is again uncertain as the quantity produced decreases but prices increase.

Figure 51. Illustration of shifts in customer and producer surplus



As a first step in the CBA, the relative features and services that MRAs and transmission can produce for beneficiaries should be considered. As we discussed in Chapter 1, transmission solutions offer a broad range of benefits. However, currently, most system planners evaluate the non-reliability benefits of transmission in terms of production cost reductions, and do not frequently consider the many other benefits transmission can provide. Comprehensive consideration of the full range of benefits a proposed solution can provide is critical to evaluating MRAs and transmission on an equal footing. Focusing solely on production cost savings will provide misleading results, as MRAs are often less expensive than transmission even though a more costly transmission investment may result in greater net benefits.

Appendix B provides a description of the core benefit metrics that LEI recommends for consideration and discusses their importance to system planners, system operators, and customers, and describes the techniques for measuring such benefit metrics.

4.3.1.2 Cost Metrics

In the other part of the CBA, the costs of each solution need to be quantified. Similar to benefits, there is a broad variety of costs that should be considered beyond the investment and operating costs of transmission, for example, negative externalities and transaction costs. Appendix B provides more details.

4.3.2 Tools

In order to quantify the costs and benefits, system planners will need to deploy a variety of tools. These include tools that evaluate the technical elements of the solution (i.e., its ability to meet a defined need); tools that quantify and measure the benefits and costs, and tools that address uncertainty in the analysis and uncertainty of the investment decisions and tradeoffs between transmission and MRAs.

4.3.2.1 Tools to Evaluate the Technical Elements of the Solution

At the onset of their analysis, system planners will need to identify the driver behind the proposed project. Transmission projects are generally driven by one of three items: reliability, market efficiency, or public policy. Once the driver or need has been identified, system planners must then deploy the tools necessary to ensure that the proposed solutions are technically able to meet that identified need. While projects are typically envisioned to meet one of the needs below, investment decisions should be made based on the full suite of benefits and costs. Indeed, transmission projects proposed for one need could be expanded to provide significantly more benefits for a modest incremental cost.

1) ***Reliability:*** Reliability needs are measured both in terms of system security and resource adequacy.
2) ***Market Efficiency:*** Projects may be proposed to improve market efficiency of a system. For example, if a system is heavily congested (i.e., with some regions having a higher wholesale price than others), solutions could be introduced that would reduce congestion.
3) ***Public Policy:*** Project may be proposed to assist in meeting public policy goals. For example, the Tehachapi Project was proposed and implemented to help meet California's renewable energy goals.

4.3.2.2 Tools for Quantifying Costs and Benefits

In order to quantify the full suite of benefits and costs, system planners will need to deploy a variety of tools, including:

- ***Energy market simulation model:*** a production cost-based simulation model can be used to capture system operations and to forecast market prices These simulation tools will make it possible to capture price reduction benefits (coming from energy markets), production efficiency gains, environmental benefits, reliability and resource adequacy benefits, among others.

- ***Capacity or resource adequacy simulation model:*** a capacity model is used to simulate the price outcome of capacity markets. A capacity model can be used to capture the price reduction benefits coming from capacity markets.

- ***Emissions model:*** an emissions model can be used to capture the emissions reduction benefit due to a project, either an MRA or a transmission project. The primary driver of the emissions reduction is the injection of additional zero or low-emissions resources from a new project, displacing the dirtier resources. Simply put, the emissions reduction benefits can be calculated as the reduced emissions level multiplied by the emissions cost.

- ***Renewable Portfolio Standard ("RPS") model:*** an RPS model includes the analysis of qualified renewable energy supply and renewable energy requirements (i.e., demand for RPS). From the model, we can determine if a system can meet its RPS requirement over time and if the RPS requirement can be met more economically with a new project.

- ***Strategic bidding model:*** a strategic bidding model is used for predicting how competition and bidding behavior would react to a new investment. This would allow planners to quantify the competitive benefits of a solution.

- ***Macroeconomic model:*** a macroeconomic model is used for predicting how the construction and operation of a new transmission or MRA solution would impact the local and/or regional economy. During the construction stage, the hundreds of construction jobs created as a result of construction and installation of a proposed transmission line (and converter station/substation) or an MRA is the direct labor market benefit of the project. Then, these construction workers spend their pay checks and that creates additional benefits for other sectors of the state economy. In the commercial operations phase of a project, economic benefits will continue in the form of new, permanent jobs for O&M and also as a result of payment of property taxes to local governments and other potential fees. In addition, it is expected that the transmission project, once energy is flowing, would lead to a reduction in the net costs of electricity for customers. These ratepayer impacts will need to be reflected at the end user level and would positively and meaningfully impact the state economies. A macroeconomic model will quantify the macroeconomic benefit due to the construction or introduction of a solution.

4.3.3 Parameters of Analysis

When performing a CBA, it is important to define certain key parameters to ensure that the analysis is internally consistent and will yield results that can be compared on an "apples to apples" basis across the proposed solutions. These parameters include: (1) a baseline against which all solutions will be compared; (2) the timeframe over which the benefits and costs will accrue; and (3) the valuation method that will be used to arrive at a final dollar value for the net benefits of each solution.

4.3.3.1 Building a baseline

It is important that all possible solutions are tested against the same criteria and baseline system conditions, so that there is a level playing field for the various transmission solutions and MRAs. That is, MRAs and transmission must be considered on equal footing. The baseline should be reflective of the actual commercial realities of the target system, including a proper accounting of the market rules and accurate representation of the market dynamics. During a multi-year analysis, it is also important to mimic private investors' (i.e., MRAs developers) decision making process. Private investors act rationally: entering the market when market condition are favorable and exiting the market when market conditions are unfavorable. MRAs and transmission may each individually impact market outcomes; the interplay between MRAs and transmission and the market should be recognized and measured (as we discuss further below in Section 4.3.4.3). In addition, the analysis should also examine the system under normal "expected" system conditions as well plausible stressed conditions (as described further in Section 4.3.4.2).

4.3.3.2 Time frame of analysis

Given the varying longevity of transmission and MRA solutions, differences in start dates, and the fact that the timing of costs and benefits may differ even on an individual solution basis, the cost-benefit analysis should be done across multiple years. If possible, LEI suggests conducting the analysis to cover the operating life of the assets, but for at least a minimum of ten years. Certain elements of the benefit projections may not lend themselves to accurate forecasts out much further than 20 years, in which case more simplifying extrapolation techniques may be necessary, in conjunction with sensitivity analysis. Furthermore, the present value will be small for the later years in any cost-benefit analysis, after we discount the benefits and costs to the present value (see below).

However, LEI recognizes that in practice the analysis horizon may need to be shortened relative to the full technical or economic life of the investments. However, the cost-benefit analysis should be sufficiently forward looking as to address both immediate priorities and evolution of the markets over the investment cycle (for example, covering the timeframe needed to bring new MRAs and/or transmission from the permitting and siting stage through construction and operations).

4.3.3.3 Valuation method

We also suggest adopting a Net Present Value ("NPV") method for discounting future benefits and costs to a pre-determined year using an appropriate discount rate. Under the NPV methodology, the discounting allows for comparability of solutions against one another. The use of discount rate will incorporate the ratepayers' risk appetite and time value of money preferences. That is, solutions providing more immediate benefits should be more highly valued than those that only provide benefits in the distant future. LEI suggests using a single discount rate across all solutions, based on the currently allowed rate of return for transmission investment in the region, which is generally in the range of 10% to 11% in the U.S.

The net benefits of all solutions can be compared either in terms of a NPV value or using a cost-benefit ratio. The cost-benefit ratio is calculated by dividing the total benefits of a proposed solution by its total costs. A cost-benefit ratio is a commonly used measure, as it implicitly normalizes for differing sizes of the proposed solutions by referring to the dollar of benefits for each dollar of costs.

4.3.4 Analytical Techniques

The cost-benefit analysis is a forecast of net benefits over a given period of time. When considering any forecast, concerns about the risks of misjudgment and error naturally arise. There are several analytical techniques that can be used to assess and manage risks and uncertainty, which can be of significant concern in a long-term forecast. These techniques can help ensure the quality of the results - that is, the extent to which they can be relied on for the purposes of system planning.

4.3.4.1 Capturing Externalities

In economics, an externality is a cost or benefit that affects a party who did not choose to incur that cost or benefit. If a negative externality exists, such as **pollution**, the producer may choose to produce more of the product than would be produced if the producer were required to pay all associated environmental costs. On the other hand, a positive externality is an action of a product on customers that imposes a positive effect on a third party. If a positive externality exists, such as in **public safety** or education, less of the good may be produced than would be the case if the producer were to receive payment for the external benefits to others.

In the electricity market, along with production cost savings and depending on the energy mix in the import and exporting markets, new infrastructure investment can reduce the total emissions of pollutants such as carbon. Carbon allowance costs are captured in the short-run marginal cost ("SRMC") of generation and therefore the market cost of carbon reductions are part of the production cost savings. For example, assuming a new infrastructure investment will reduce the carbon emissions in the market by one million tons a year (already adjusted for the carbon emitted in the exporting region) and that the carbon allowance price embedded in SRMC is $10/ton. As a result, lower carbon emissions will result in $10,000,000 savings to the generation sector, which will be captured in the production cost savings metric. However, customers may value the reduction in carbon emissions at a higher marginal price than that which is represented in the carbon allowance trading price (and in the SRMC). For example, if the social cost of carbon is perceived to be $80/ton, then the true cost to society from the reduction of a million tons of carbon would be $80,000,000 – while only $10,000,000 has been recognized in the production cost savings metric. Therefore the incremental social value of carbon emission reductions needs to capture the differential – namely, $70,000,000 pursuant to this example. The economic analysis should be able to capture the externality that a solution (either a transmission project or an MRA) could impose to a society.

4.3.4.2 Uncertainty in Exogenous Drivers

Uncertainty is one common challenge when performing any long-term analysis. Long-term analyses are usually done for at least five years, ten years, or even longer. Simulating the future state of world requires system planners to develop assumptions based on their best judgments. The assumptions that have to be made include: fuel prices, emission allowance prices, load growth, interchange between neighboring markets, retirements, and new entry, among others. The new entry decision is further complicated by factors such as the cost of various new generation technologies, the need to meet the resource adequacy requirements, and the need to meet public policy goal (i.e., renewable portfolio standard targets).

By failing to take into account uncertainty, the system planner could choose a suboptimal solution. Uncertainties can fall into one of two categories:

- **Exogenous uncertainties**: these are uncertainties driven by factors that are outside of the system you are planning for. For example, gas price uncertainty is an exogenous uncertainty.

- **Endogenous uncertainties**: these are uncertainties driven by interaction of factors that all fall within the system you are planning for. For example, the decision of generators to stay in the market or retire given defined system parameters is endogenous to the modeled outcomes and may also be influenced by the pattern of transmission investment. That is, when market prices are high, we would expect more new entry. Conversely, when market prices are low, we should expect to see some retirements. In addition, if transmission is built between certain regions, it may accommodate more generation expansion. We discuss this further in the next sub-section.

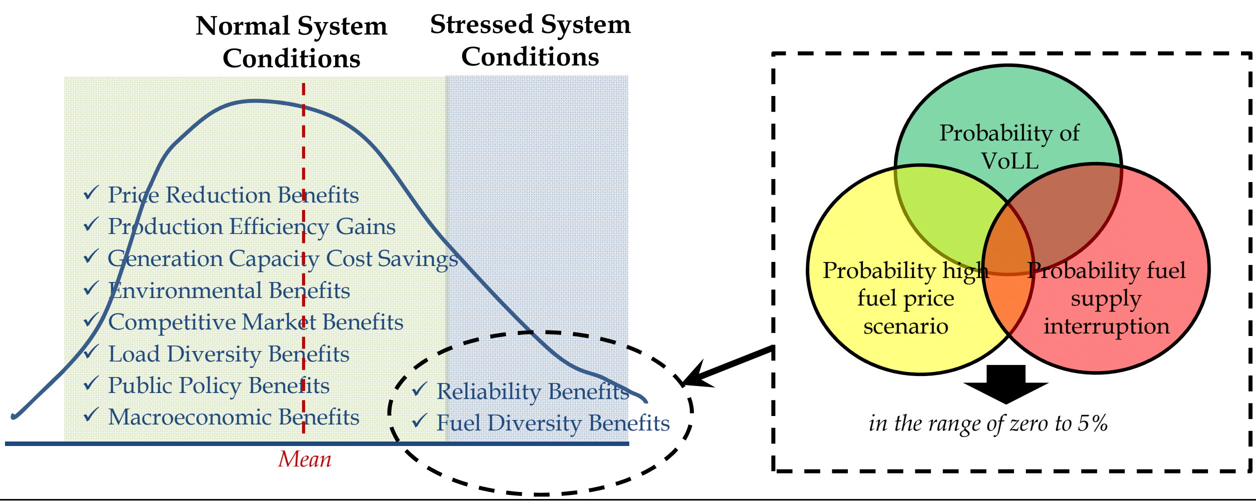
In the past, to address exogenous uncertainty and risks associated with many assumptions used to measure economic benefits of a proposed project, LEI has used a Statistical Based Scenario Analysis ("SBSA") approach in combination with its proprietary simulation modeling techniques to create a full range of potential market outcomes over the forecast timeframe. SBSA employs a statistical method known as the bootstrapping[151] (related to Monte Carlo

[151] Bootstrapping is a data-based simulation method for statistical inference, which has its roots in the idea of "resampling". Bootstrap confidence intervals are directly constructed from real data sets, using a simple computer algorithm. Bootstrap procedures take the combined samples as a representation of the population from which the data came. In contrast, traditional parametric procedures that are widely used are primarily based on several major assumptions about the population(s) from which the data came. For example, it is routine to use procedures that assume the samples come from normally distributed populations for convenience. (For instance, assuming a distribution is normal makes its mean and variance independent. Similarly, if a distribution is normal, 95% of the observations will fall within 1.96 standard deviations from the mean.) As nice as it is to be able to assume normality at the outset, and therefore infer a great deal about the data, there are problems with making such assumptions. There are cases where one can make the assumption of normal distribution, and even if that is not the case, arrive at a reasonable conclusion. However, such analysis would not be statistically robust. This is one of the reasons why we avoid assuming

analysis) for developing key input variables that ultimately drive the distribution of market outcomes (see Appendix C for more information).

Another uncertainty issue emphasizes the insurance value of a transmission project, which can also be considered in terms of optionality. For example, what happens to the system if a generator suddenly retires or goes offline? A transmission line that can bring to market alternative resources provides the "insurance value" for the electric system. As such, insurance value of transmission only arises under stressed system conditions in the tail end of the distribution of benefits, as shown in figure below. Although such events are classified as low probability (in the range of zero to 5%), they are high impact events.

Figure 52. Benefit metrics under different market conditions and their probabilities



4.3.4.3 Consistency

Consistency has two dimensions. First, in order to reduce unintended biases due to methodological considerations, it is important that all possible solutions are tested against the same criteria and baseline system conditions. In other words, there should be external consistency in the benchmark (i.e., the baseline – as described in Section 4.3.3.1). With an appropriate baseline, MRAs and transmission projects can be evaluated on an equal footing.

The second dimension of consistency refers to the internal consistency, which speaks to the causal relationships. For example, it is important that private actors' investment decisions are modeled consistently with the forecast market dynamics and that the investment are realistic given transmission planning decisions also being modeled. We refer to this also as the

that any of our inputs follow well-known distributions such as normal, log-normal, etc. The most that we are willing to assume (a critical assumption) under SBSA is that the data we have constitutes a reasonable representation of the population from which they came. We then resample from the pool of data that we have, and draw inferences about the corresponding population and its parameters.

endoegeneity problem (see textbox). This is no easy task as there is no agreed upon protocol for reconciling the generators' (or other MRAs') response to investment in transmission and vice versa. Analytical techniques are required that allow for rational investment decisions to prevail in the forward looking modeling based on observed projections and modeled dynamics. Following the path through rational investment decisions leads to the resolution of the "chicken or the egg" problem regarding whether MRAs would or would not build given transmission and vice versa, and therefore resolves the inter-dependency or endogeneity of the investment problem.

Let us provide a simple example. A generation investors' profits are, in part, contingent on future transmission investments. On the other hand the benefits of transmission are, in part, dependent on generation investment. If generation investment is a substitute for a transmission project, then investing in both can be wasteful from the societal perspective. On the other hand, if generation is complementary to transmission investment, the transmission project may be required to catalyze incremental socially efficient investment. That is, in the absence of a leading transmission investment, certain socially beneficial generation investments may not take place.

In a very stylized game theoretic framework where investment decisions are discreet (invest or not invest) and there is only one generation investor and one transmission investor, the interaction between the two players can be summarized in a simple, two-dimensional strategy decision, as shown in the text box on the next page. The solution to this strategic decision from a transmission planner's perspective depends on the social value of the investment, given the set of conditions in each of the four discrete outcomes. In other words, as part of the planning process, the outcomes under each of these four alternatives need to be modeled (with the generators' best response in each case under the modeled circumstances). Moreover, it is important to consider that the optimal generation investment strategy from the generation

Endogeneity

Broadly speaking, an endogeneity problem implies that a model does not properly capture the way causation works in the real world.

For the purposes of this paper, endogeneity is referenced in terms of the two way causal relationship between the transmission investment decision and the generation (MRA) investment decision. That is, the decision to invest in generation depends on the availability of transmission to reach market (is the generator able to sell its output?) and placement of new transmission may also impact the market revenues that the generator would receive (i.e., the benefits of generation, which drive the investment decision). On the other hand, to the extent that one of the benefits of transmission is to reduce congestion, the location and operations of generation (as well as the siting of new generation) would also impact the magnitude of the estimated benefits and presumably impact investment decisions in transmission.

In order to solve the "optimal" investment path for transmission, one must consider the decisions of generators, which means identifying the "rational response" of generators to new transmission.

		Generation Investor's Strategy Choices	
		Invest in generation	Delay investment in generation
Transmission Investor's Strategy Choices	Invest in transmission	*(Generation Investment and Transmission Investment)*	*(Transmission Investment Only)*
	Delay investment in transmission	*(Generation Investment Only)*	*(No Investment)*

owner's perspective may not coincide with the optimal generation investment strategy from society's (and thus the transmission planner's) perspective. While the transmission planner seeks to maximize benefits to the customer and society as a whole, the generators also seek to maximize private benefits or profits associated with operation in a deregulated, competitive power market. The transmission planner should then select one of the four options based on the combination of investments that maximizes the economic benefits to customers.

In reality, markets are more complex, comprising many MRA technologies and independent investors and multiple transmission investment opportunities. We can resolve these complexities using backward induction techniques in conjunction with simulation modeling. The process starts with a baseline model where the system planners start with the most likely set of assumptions on key market drivers, like official long-term demand forecast; market-based outlooks on fuel prices and carbon allowance costs; rational, economic retirements; and reasonable generic new entry based on resource adequacy requirements, economics, and inclusive of current policies (like Renewable Portfolio Standards). If there is only one qualified transmission solution, then one would model two scenarios: with and without transmission solution. If there are multiple transmission solution(s), then there will be additional variations on the "solution" scenarios. If there are also qualified MRAs, then the scenario space can be expanded to further include those projects as possible alternative solution(s).

The modeling is then performed over a multi-year horizon. At this time, each scenario's assumptions need to be calibrated to reflect rational market participants' response to that transmission solutions (or lack thereof). A transmission project(s) could delay a generation investment or, on the contrary, it could motivate a generation investment (like CREZ in ERCOT). Once the transmission solutions are implemented and competitive response from various MRAs estimated, then the projected market outcomes can be used to estimate the net benefits

In effect, through the process of simulation modeling and calibration to rational and consistent response from MRAs, the modeled scenarios would have resolved the uncertainty in the longevity of MRAs and their status as a substitute or complement. From the various future outlooks, the system planner selects the optimal solution out of a pool of alternatives. For more detailed discussion on addressing endogeneity of investment decisions, please refer to Appendix D.

In addition to using this type of analysis to understand the dynamic impacts from building/not building a transmission project, many planners use scenario analysis to understand and quantify some of the uncertainties in planning a long term investment. Sometimes the scenarios include a "base" or "business as usual" scenario followed by scenarios that contain various transmission solutions and technically-suitable MR solutions. In addition, this methodology allows for the inclusion of the uncertainties in other exogenous drivers, as the scenarios can be repeated to consider various exogenous market factors (such as varying assumptions on future natural gas prices, etc.). Scenario analysis is built on "plausible" futures that are intended to envelope the range of the more likely outcomes. However, more extreme "stress" tests are also valuable, so that planners can get a more comprehensive assessment of benefits.

4.4 Conclusion

We recognize that system planners may have their own approaches and planning processes in place and therefore we have not specified a "one-size fits all" approach, but rather focused on the major components that we believe would yield an effective consideration of MRAs within the transmission planning process (i.e., the toolkit for system planners). The major elements of the toolkit are:

- Use of a flexible framework, such as cost-benefit analysis, which allows for comparative analysis of various MRAs and transmission solutions on comparable basis, even if the characteristics and services provided vary. This involves identification of benefits and costs, and setting out how one measures those and from whose perspective.
- Selection of tools that can evaluate and measure the expected benefits and costs on a realistic basis.
- Use of analytical techniques that deal with challenging aspects of economic cost-benefit analysis, such as uncertainty.

Our recommended analytical techniques likely require more modeling analysis and data collection than is done today within the transmission planning process. However, it is not intended to be overly cumbersome or require effort that will extend the timeframes for analysis and decision-making and therefore undermine the timeliness of the decision-making process. As we show in Appendix A, the tools and analytical techniques can be deployed in such a way to streamline the overall process, and winnow down the pool of projects that require a full cost-benefit analysis. Furthermore, as we discuss in Appendix B, many of the benefits can be quantified using results from the same simulation modeling tool. To the extent that system planners are able to clearly define what analyses they will conduct and in which order, that will help reduce the time needed for analysis. Nevertheless, LEI recognizes that more time and effort are needed to yield effective outcomes in this complex issue of MRA and transmission analysis.

In conclusion, we want to emphasize that what we have tried to do here is not to create a process but to recommend the building blocks that a system planner can employ as part of their current practices. In fact, the benefits that we are recommending to be measured are already considered in many instances by system planners, and many tools are also part of the standard toolset at ISOs/RTOs. Even some of the analytical techniques are already be in use at some RTOs. For example, CAISO considers uncertainty by using probabilistic techniques.

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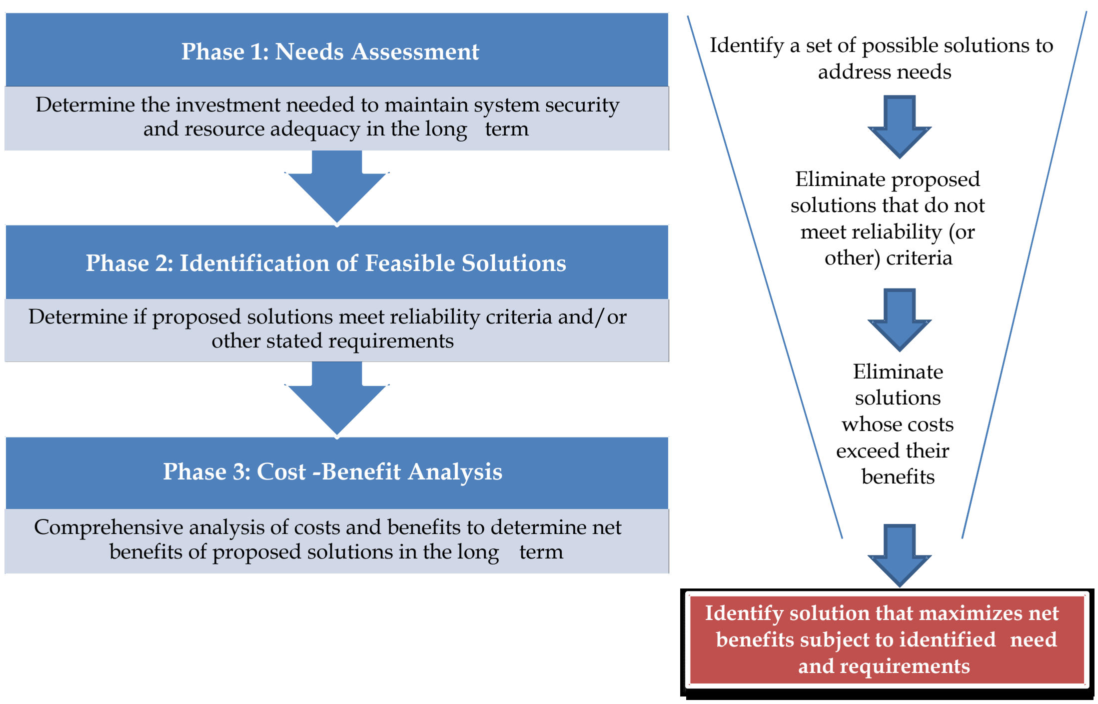
Appendix A: Illustrative Process

In Chapter 4, we presented a set of analytical tools and analytical techniques that can be incorporated into existing processes to effectively evaluate MRAs in the system planning process. Recognizing that ISO/RTOs may already have customized approaches for system planning in place, we did not recommend a specific process. However, in this Appendix, we demonstrate one possible way to incorporate and deploy the various tools and analytical techniques for the purposes of evaluating MRAs alongside transmission during the planning process. Regardless of the variations between system planning processes across markets, the key to effectively evaluating MRAs in the system planning process is to ensure that the set of analytical tools and analytical techniques are deployed within the discipline of cost-benefit framework at some point during the planning process. Our suggested analysis is a more comprehensive approach that, even given the extra resources and time required to perform the analysis, should maximize the benefits derived from any investment (transmission, MRA, or some combination thereof). At the core of this framework is a comprehensive cost benefit analysis that considers a broad range of potential benefits and costs.

Our illustrative approach consists of three key phases: (1) a needs assessment; (2) identification of feasible solutions; and (3) a comprehensive cost-benefit analysis (including an economic analysis of benefits and a comprehensive estimate of costs). Through these phases, solutions to identified needs are proposed, evaluated, and ultimately eliminated or selected.

Figure 53. Sample Analysis



5.1 Phase 1: Needs Assessment

As a first step in our sample analysis, a needs assessment is performed. There are two dimensions when performing a needs assessment: reliability needs and the needs for improving market efficiency. A reliability needs assessment is an evaluation of resource adequacy and transmission security, which determines if reliability criteria are met or whether there are system inefficiencies. Reliability needs are measured both in terms of system security and resource adequacy:

- **System security** is the system's ability to withstand sudden disturbances, and is measured *deterministically*. In transmission planning, system security is measured through detailed system engineering analysis. In the U.S., system planners test system security by analyzing the system's ability to meet reliability criteria, such as NERC Reliability Standards, using power flow models. For example, transmission engineers conducting a needs assessment develop a series of stress tests that consider a variety of possible contingencies (such as NERC's N-1 or N-1-1 criteria) and analyze whether the system is reliable under those conditions.

- **Resource adequacy** is the ability for the system to supply the total demanded quantity of energy, and is measured *probabilistically*. That is, system planners use probabilistic analysis to determine an optimum plan for transmission system expansion that minimizes the expected costs (which include both construction and outage costs), using a probabilistic reliability criterion known as the loss of load expectation ("LOLE"). The optimum value of the reliability criterion is determined at the minimum value of the combined total of the cost of constructing new transmission and the customer outage cost associated with supply interruptions.

Deterministic vs. Probabilistic Analysis

Deterministic: all data is known beforehand (i.e., the system's current state and key inputs); the model will perform the same way every time for a given set of conditions.

Probabilistic: an element of chance is involved. You know the likelihood that something will happen (loss of load expectation) but don't know when it will happen.

The needs assessment should also consider projects that can improve market efficiency of a system even though there is no need for reliability concern. For example, if a system is heavily congested (i.e., with some regions having a higher wholesale price than others), a system planner should assess the needs for reducing congestion by introducing solutions.

The goal of Phase 1 is to generate a set of possible solutions to the identified system or market needs. These solutions are then evaluated during the next two phases of the framework, as described below.

5.2 Phase 2: Identification of Feasible Solutions

After the needs are identified, the transmission planning process moves to the optimization stage, where the goal of the system planner is to seek out the best solution(s) subject to meeting the reliability requirements. Optimality is considered in terms of net benefits, and reliability requirements are, therefore, constraints on the optimization process.

The process to determine if the reliability requirements are met is similar to what transmission planners are routinely doing today with some modification of the scope. With the introduction of MRAs, transmission planners will need to identify MRAs as possible solutions and then test them to ensure that they are technically equivalent to proposed transmission solutions under realistic system operating conditions as well as contingency scenarios. In other words, this analysis confirms and ensures that the identified MRAs actually solve the reliability problems of the system. After all, the key goals of the investment, either transmission or MRAs, is to solve the reliability concerns and to maintain a robust electric infrastructure. However, as previously discussed, one of the more common limitations of proposed MRAs is that they cannot meet or solve all the technical requirements that a transmission solution effectuates.

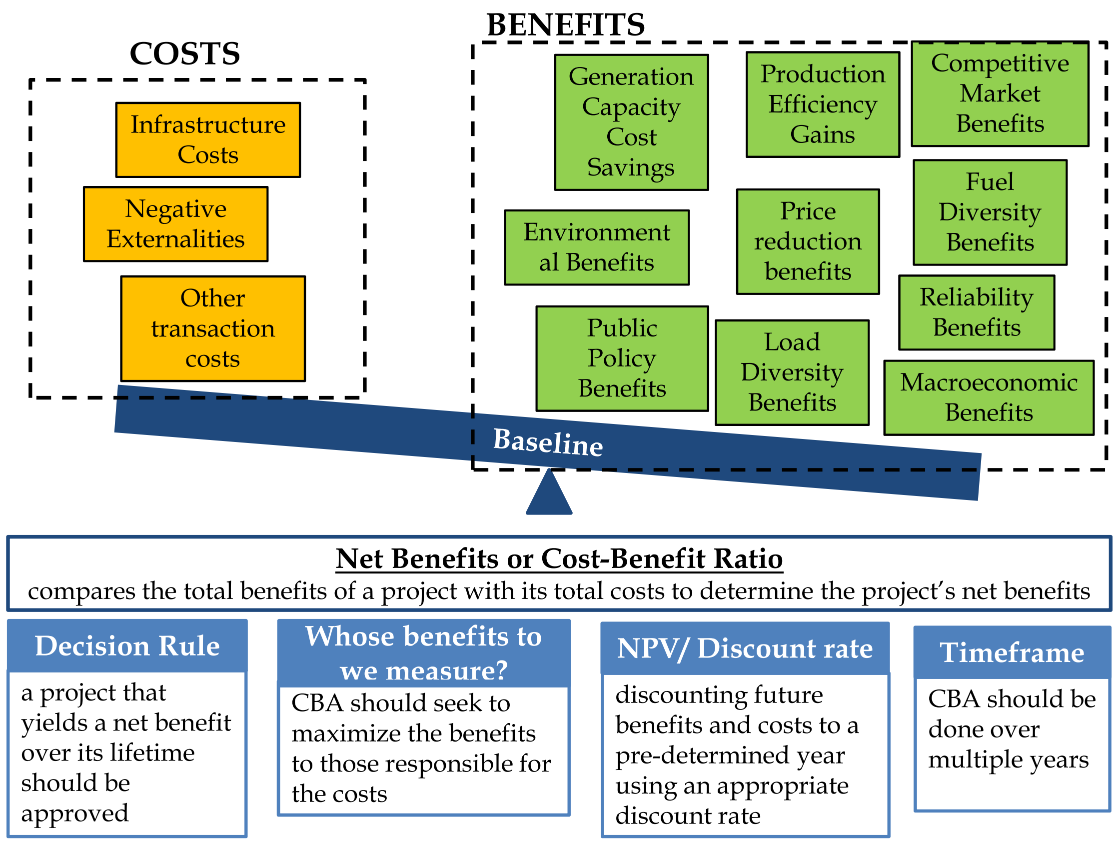
It is also important to note that, to the extent that a set of solutions has been proposed for a reason other than reliability (such as for policy objectives, or to solve market inefficiencies), the solutions must also meet these criteria as well. That is, solutions for non-reliability driven projects must meet the stated "need" in addition to meeting the reliability criteria (i.e., not have a negative impact on system reliability as measured by NERC standards and other criteria).

At the end of Phase 2, solutions that do not meet the reliability requirements (or other stated requirements) are eliminated. The remaining solutions are then evaluated in the final phase of the framework.

5.3 Phase 3: Comprehensive Cost-Benefit Analysis

Cost-benefit analysis ("CBA") is a method of evaluating the economics of a project (or investment). It can be used to analyze a specific project and also to compare across and select from multiple projects. Under a CBA, one compares the total benefits (gross benefits) of a project with its total costs to determine the net benefit of a project as shown in the figure on the next page. Generally speaking, a project should be pursued if benefits exceed the costs (that is, if it had a positive net benefit).

Figure 54. Illustrative Cost-Benefit Analysis



Appendix B: Quantifying Benefits and Costs

The goal of a cost-benefit analysis is to quantify, to the extent possible, the full set of costs and benefits associated with any proposed solution (transmission or MRA). That is, the outcome of the CBA can be mathematically represented as follows:

$$NPV = \frac{B_0 - C_0}{(1+d)^0} + \frac{B_1 - C_1}{(1+d)^1} + \ldots + \frac{B_t - C_t}{(1+d)^t} > 0$$

Where B = benefits
C = costs
D = discount rate

Our framework seeks to quantify a broad range of benefits and costs. In some instances, the quantification is relatively straight forward. However, in others a more complex approach needs to be taken. Below, we provide some suggestions as to which benefit and cost metrics should be considered, and how each metric could be quantified.

6.1 Benefit Metrics

As a first step in the CBA, the relative features and services that MRAs and transmission can produce for beneficiaries should be considered for all qualified MRAs and transmission solutions (i.e., those that meet the driving criteria). As described in Chapter 1, transmission solutions can often offer a broad range of benefits. However, currently, most system planners evaluate the non-reliability benefits of transmission in terms of production cost reductions, and do not frequently consider the many other benefits transmission can provide. Comprehensive consideration of the full range of benefits a proposed solution can provide is critical when evaluating MRAs alongside transmission. Focusing solely on product cost savings will provide misleading results, as MRAs are often less expensive than transmission even though a more costly transmission investment may result in greater net benefits.

Below we provide a description of the benefit metrics that LEI recommends for consideration and their importance to system planners, system operators, and consumers.

- **Price reduction benefits**: Market price reduction benefits arise when a solution (either a transmission project or an MRA) creates a reduction in the market clearing price for energy, capacity or other ancillary services. Through the dynamics of supply and demand, transmission and/or MRAs may be able to lower market price. For example, transmission expansion may allow lower cost resources to be exported into the market, which would drive down market prices.

  Market price reduction benefits should be calculated as the change in market price multiplied by demand. The "without solution" notation in the formulas below effectively represents the market outcome under the base case or "business as usual" case, which is used as a benchmark across all projects in order to provide the consistency discussed in Chapter 4. The formulas below outline the general calculation for the energy market and the capacity market (and the same logic could be extended for other services that are affected by a solution, such as RECs and ancillary services):

$$\sum_{\substack{t = \text{Energy, capacity,} \\ \text{A/S and REC markets}}} \left(\text{price}_{t\,\text{Without a solution}} - \text{price}_{t\,\text{With a solution}} \right) \times \text{quantity*}_t$$

- *Quantity here refers to the total energy consumed in a given period or total capacity procured*

- **Production efficiency gains**: Efficiency gains can occur when a solution allows the system to dispatch resources in a more efficient manner. Efficiency gains are a technical measure of the productive efficiency of the network (including the transmission and generation). In the context of energy markets, production efficiency gains are generally measured by reference to the short run marginal cost ("SRMC") of generation/production.[152] The formula to consider production efficiency gains in the energy market is as follows:

$$\left\{ \sum_{\substack{t = \text{every generation} \\ \text{units on the system}}} \text{marginal cost}_{t\,\text{Without a solution}} \times \text{production quantity}_{t\,\text{Without a solution}} \right\} \text{minus}$$

$$\left\{ \sum_{\substack{t = \text{every generation} \\ \text{units on the system}}} \text{marginal cost}_{t\,\text{With a solution}} \times \text{production quantity}_{t\,\text{With a solution}} \right\}$$

- **Generation capacity cost savings:** Generation capacity cost savings arise when a solution defers or obviates the need for investment in generation assets. It can also be thought off as the avoided cost of investment or the option to delay investment. This will also be calculated typically by evaluating the quantity of investment that can be postponed relative to the base case and then monetizing that quantity by the unit costs of investment.

- **Environmental benefits:** Environmental benefits include the incremental social value of environmental attributes, such as reduction in the emissions of key pollutants. Currently, there is significant focus on how infrastructure investments can reduce the emissions of carbon.[153] Once the total tons of avoided emissions is identified, then the social benefits can be calculated based on the accepted social cost of that pollutant (in the case of carbon, based on the estimated social cost of carbon).[154]

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[152] There can also be production cost gains in the capacity market, which would then represent a reduction in fixed costs of production.

[153] Other pollutants can also be evaluated, such as sulfur dioxide and nitrogen oxide, but the changes are likely to be modest in comparison to carbon reductions, given that prior environmental regulations and technological advancements in generation technology and abatement equipment have made significant strides in reducing the emissions of those pollutants.

[154] For a sample measure of the social cost of carbon used by the US EPA, please see http://www.epa.gov/climatechange/EPAactivities/economics/scc.html

- **Competitive market benefits**: Typically, in estimating wholesale price reductions benefits and production cost savings, the simulation models employ assumptions of perfect competition and therefore may overlook the potential competitive benefits that could be attributed to strategically-placed new infrastructure. It is possible to relax this strict assumption of perfect competition in the modeling analysis (which would be consistent with real world market operations since generators can submit offers that deviate from SRMCs).[155] To quantify competitive benefits, we need to start with a "new" baseline, where wholesale energy prices include a potential mark-up on SRMC based on scarcity conditions and the portfolios of individual generators. We then observe how the market reacts under these relaxed market offer assumptions when a transmission or MRA solution is introduced. In other words, we look at the system price difference with and without a solution under such market behavior.

- **Fuel diversity benefits**: Increasing reliance on a single fuel resource, such as natural gas, is a concern for system operators and regulators across the U.S. because electricity markets are then subject to the constraints of fuel supply infrastructure (for example, gas pipelines). The concern of relying on a more concentrated fuel mix lies in (1) greater exposure to higher fuel prices and (2) increased risk of electricity supply interruptions if the fuel is not available. The higher fuel price is a direct result of additional demand. The second benefit associated with fuel diversity relates to the risk of supply interruptions. If a system has a balanced fuel mix, it may be capable withstanding a fuel supply interruption by using other type of generation to meet electricity demand.

  Fuel diversity benefits can be evaluated quantitatively through simulation modeling, and the impact of a solution that reduces reliance on a more concentrated fuel mix will create benefits to consumers. In order to assess the first concern, a similar approach to measuring price reduction benefits should be applied, but with the baseline outlook that reflects high fuel (gas) prices (one also needs to establish a probability for the occurrence high price outcomes). The reduction in energy prices associated with a solution, probability adjusted for the occurrence of those high fuel prices, would provide a valuation of the avoided costs of exposure to high fuel prices.

  To address the second concern, the assessment of reliability benefits serves as an example of the basic construct for estimating these benefits. One would need to create a gas pipeline stress scenario (e.g., a failure of the gas pipeline network) and then evaluate how a solution reduces the likelihood and extent of loss of load (because of insufficiency of supply). The change in the probability of loss of load, coupled with the probability of the gas failure events, would then be multiplied by the value of lost load ("VoLL") measure to establish the value to consumers from avoiding supply interruptions that could be caused by the systems dependence on gas.[156]

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[156] Note that both reliability benefits and fuel diversity benefits are looking at the system reliability issue. However, reliability benefits quantify the benefits of additional supply while fuel diversity benefits quantify the benefits of a variety type of generation.

Once the simulation modeling cases are complete under the higher gas scenario and the gas system failure scenario, and then the generic formula to estimate fuel diversity benefits is described below by reference to the resulting wholesale energy prices and probabilities:

<u>Benefits of reducing fuel supply interruption</u>

$$\left[\,\#\text{ of VoLL}^{\text{Under gas pipeline stress scenario}}_{\text{Without a solution}} - \#\text{ of VoLL}^{\text{Under gas pipeline stress scenario}}_{\text{With a solution}}\right] \text{ x } \begin{array}{c}\text{monetary}\\ \text{value of VoLL}\end{array} \text{ x } \begin{array}{c}\text{probability}\\ \text{of VoLL}\end{array}$$

<u>Benefits of reducing fuel price volatility</u>

$$\left[\,\text{price}^{\text{Under high gas scenario}}_{\text{Without a solution}} - \text{price}^{\text{Under high gas scenario}}_{\text{With a solution}}\right) \text{ x quantity } \text{ x } \begin{array}{c}\text{probability adjusted}\\ \text{for the occurrence}\\ \text{of high gas}\end{array}$$

The monetization of the fuel diversity benefits described above is not simple. If desired, the fuel diversity benefit can also be considered using a generalized ranking approach that then allows for assessing the extent of fuel diversity of a market under varying solutions. For such a comparative analysis, we would recommend calculation of a concentration ratio that shows the concentration of various fuel types – much like a Herfindahl-Hirschman Index ("HHI"), which shows the concentration of ownership in a given market. The fuel diversity concentration ratio can be calculated as follows:

$$\sum_{t = \text{ fuel type}} \left(\text{market share of each fuel}_{t}\right)^{2}$$

- **Load diversity benefits:** A solution can potentially change the load pattern in an area, either on a seasonal basis or for a typical day. For example, a demand response resource can reduce the demand during peak hours, which can delay the needs for peaking capacity. If a transmission project can connect two regions with complementary load profiles or resource mix, it will also help to delay the needs for additional supply. This is similar to the concept of "trade benefits". For example, Region A has a flat load profile but its fuel mix is more concentrated on peaking resources. Region B has a peaking load profile but its fuel mix is more concentrated on baseload resources. If a solution can connect Regions A and B, then their load prod profiles and fuel mix resources can complement each other and the system planner does not need to build baseload resources in Region A originally designed to serve the load in Region A exclusively and vice versa.
- **Reliability and resource adequacy benefits**: A solution can potentially improve system reliability. The reliability benefits can also be viewed as the ***insurance value*** to the system associated with a specific solution, and specifically insurance against interruption of service. The estimated wholesale price reductions benefits and production cost savings described

above are typically based on normal system conditions, so in effect, they would exclude consideration of reliability benefits that materialize only when the system is under stress.

We would therefore recommend that the reliability benefits be estimated by simulating stress system conditions with and without a solution and evaluating how a solution changes (reduces) the loss of load expectation ("LOLE") for the system under those system stress conditions. The change (reduction) in the probability of a loss of load event can then be monetized against the value of electricity to consumers, which in economic terms is typically referred to as the Value of Lost Load ("VoLL"). Previous economic studies have indicated a VOLL of over $25,000/MWh for non-residential consumers.[157] Once the simulation modeling is complete under stress system conditions and the change in the LOLE has been estimated, then the generic formula to estimate reliability benefits is described below:

$$\left[\ \#\text{ of VoLL}\ {}^{\text{Without a}}_{\text{solution}} - \#\text{ of VoLL}\ {}^{\text{With a}}_{\text{solution}}\ \right] \times \text{ monetary value of VoLL}$$

- **Public policy benefits:** Proposed solutions can also contribute to public policy goals. Some states in the US have the Renewable Portfolio Standard ("RPS") targets, and in some states, the environmental attribute that public policy has identified is even monetized in the form of a Renewable Electricity Certificate ("REC"). Renewable resources may be limited in a particular region or state. If a solution (i.e., transmission project) can help transport the energy generated from remote renewable resources to the market in need, it can help the state/region achieve its RPS and also reduce costs for load under the REC trading programs. But transmission is not the only option. For example, some MRAs can also accommodate similar public policy initiatives. An energy efficiency project can also indirectly help a region meet its RPS. Although energy efficiency may not be a renewable producer, it can reduce the RPS target level as the RPS target is conventionally measured in energy terms (in MWh). Another example of public policy relates to carbon emissions. There are market-oriented carbon reduction programs in certain states, like Regional Greenhouse Gas Initiative ("RGGI") in the northeast region of the US. The development of energy efficiency and distributed generation (mostly solar DG) can help to reduce the carbon footprint and meet the carbon compliance policy of the state or region.
- **Macroeconomic benefits:** A solution may also create indirect benefits to consumers, through expansion of the local economy. Local macroeconomic development benefits can be measured using input/output measures or more complex simulation based models, both of which track how electricity impacts other industries and sectors of the economy. For example, if a transmission project facilitates price reduction benefits, that will also mean that end-users will be paying less and therefore have more disposable income to spend on other goods and services.

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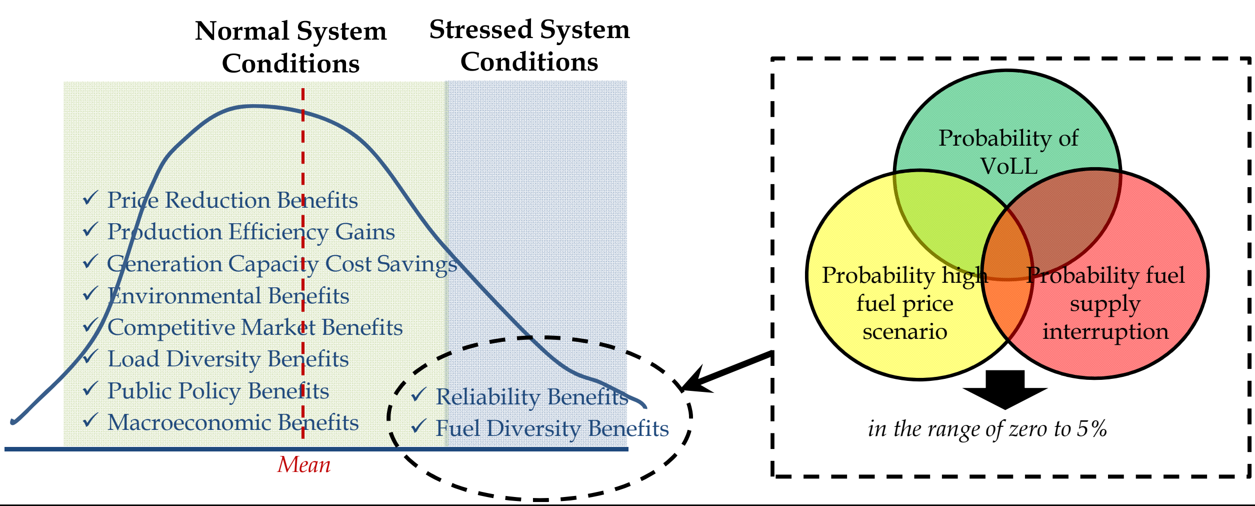
[157] Ernest Orlando Lawrence Berkeley National Laboratory. *Estimated Value of Service Reliability for Electric Utility Customers in the United States.* June 2009.

It is useful to separate the local economic development benefits into phases. For example, when a solution is introduced, there will be local spending for construction and equipment and material purchases, procurement of permits and land. Once a solution is complete and begins operation, there will be local spending in the form of tax payments and potentially also land lease payments and O&M (operations and maintenance). There may also be additional economic benefits if the project reduces on a net basis electric rates (in effect, if the direct benefits to consumers exceed the increase in transmission costs).

When considering the benefit metrics listed above, there are a number of challenging questions. For example, are some metrics more "important" than others (i.e., should one metric have more weight than another)? Note that some benefits may be transfers between consumers or from producers to consumers, while other benefits represent efficiency improvements. However, consumers can benefit from both transfers and efficiency improvements. As presented, we do not believe that the benefits we have listed are duplicative, and therefore, for the purposes of a cost-benefit analysis, they can be aggregated. However, LEI does suggest that system planners consider the weighting adjustments, as is already standard practice in some RTOs. For example, PJM assigns 50/50 for wholesale market price reduction benefits and production cost benefits when conducting a market efficiency analysis.

Furthermore, it is worth exploring the issue of probability adjustment. Some of the benefit metrics we have discussed above only occur in extreme market conditions, while others occur under normal market conditions (see Figure 55 below). Therefore, it is important that the probability of occurrence is considered in the value *before* aggregating the benefits.

Figure 55. Benefit metrics under different market conditions and their probabilities



6.2 Cost Metrics

As a second part of the CBA, the costs of each solution need to be quantified. Similar to benefits, there is a broader variety of costs that should be considered beyond the production costs historically considered. LEI suggests consideration of the following cost metrics:

- **Infrastructure costs**: This cost figure would represent the capital investment and operating costs of a solution.

- **Negative externalities:** Depending on the characteristics of a solution, the system planner may need to increase the procurement of certain ancillary services to "integrate" the infrastructure into operations.[158] For example, if there are significant wind resources built along with new transmission, the system planner may need to increase procurement of regulation service to balance the system – an increase in the regulation procurement target may in turn also raise the regulation clearing price. Alternatively, if a solution is of significant scale (and/or location), it may raise the system's first or second contingencies and therefore require the system operator to buy more reserves, which may also raise reserve prices. In both of these examples, the incremental integration costs may be associated with both price changes and volume changes.
- **Other transaction costs**: These costs would represent general transaction costs such as management costs, staff costs, financing costs, and advisory fees. Finally, in the spirit of considering uncertainties in benefits, it is also important to consider uncertainties in costs. So as part of transactions costs, to the extent it can be verifiably measured and monetized, the uncertainty regarding investment costs can be considered.

[158] In cost-benefit analysis in other jurisdictions, such incremental costs of system operations have typically been allocated to the specific project in evaluation, even if they are paid for by consumers.

Appendix C: Analyzing Uncertainty in Exogenous Drivers

In order to capture the range of benefits (and costs) of transmission and MRAs, it is important to acknowledge that market conditions - against which the value of the services of transmission and MRAs is measured - are variable and uncertain. As discussed in Chapter 4 and in Appendix B, many of the benefits are quantified by reference to the same Base Case or baseline for external consistency. However, many of the drivers that impact the Base Case are not certain. There is in fact a distribution of possible outcomes based on range of values for key drivers (i.e., gas prices, demand, etc.). As mentioned in Chapter 4, LEI has addressed uncertainty in exogenous drivers by using a combination of statistical and simulation modeling techniques. LEI's Statistical Based Scenario Analysis ("SBSA") approach in combination with its proprietary simulation modeling techniques allows for the potential evaluation of a full range of future market outcomes and therefore evaluation of benefits from new transmission or MRAs.

LEI's SBSA approach is composed of five steps:

1. **Identify key drivers.** These are the key market drivers (i.e., input variables) of the market prices and outcomes. These can include exogenous drivers such as gas prices, demand, supply, and carbon emissions.

2. **Analyze historical data.** In this step, historical data - actual observations – are analyzed and actual market outcomes are used as basis for the "population" from which each key drive is sampled. To the extent that sampling is from actual historical data, the need to make definitive assumptions regarding the parameters (such as mean, standard deviation) or the distribution of the inputs can be avoided. In some instances, it may be impossible to have actual historical data from which to sample for a particular driver (for example, long term trends in gas prices); therefore, some assessment of marginal probabilities (and assumption around the underlying distribution for that parameter) may be needed.

3. **Build a "scenario space".** The third step involves building a scenario space that consists of the empirical distribution for each of the identified drivers, and then sampling with replacement from the input scenario space. If there are time constraints involved with the modeling exercise, the number of simulations can be limited. However, the potential number of combinations, as will be discussed further below, is likely to be far greater than can be processed by a simulation model within a reasonable amount of time (especially if multiple solutions need to be evaluated). Therefore, we typically use other statistical techniques to condense the scenario space. One well known technique is the Latin Hypercube Sampling technique; it creates a stratified sample of possible scenarios to capture the cumulative

Latin Hypercube Sampling ("LHS") technique vs. conventional random sampling techniques

Traditional random sampling can produce poor coverage of the variable space. For example, sampling 5 values from the range 1-100, it is possible, though relatively unlikely, that all five samples are greater than 50. With LHS, we might pick one value from the range 1-20, one from 21-40, etc.

distribution function for expected market prices.

4. **Conduct simulation modeling.** The fourth step utilizes a simulation model as an analytical vehicle for transforming the input samples into market prices and therefore benefit estimates. In this context, this simulation model is being used akin to an economically robust "equation" to transform various market drivers (i.e., inputs) into output (market prices) estimates. Use of a simulation model as an analytical transformer eliminates the need for estimating joint probabilities of various combinations of input scenarios, which would need to be deployed if one were to use Monte Carlo extrapolation techniques.

5. **Build the sampling distribution.** The final step involves building the resulting distribution (referred to as the "sampling distribution") of market prices (or benefits) as developed through these numerous simulations of sampled inputs. Based on the applications of the Central Limit Theorem, the standard deviation of this sampling distribution is a proxy for the standard error of the sampling distribution of the population mean, and can be used to make an inference regarding the population (i.e., the distribution of the benefits).

In the sections below, we will use natural gas prices as an example to illustrate how to resolve uncertainty in exogenous driver. The natural gas price is an important market driver in most US markets. There are two dimensions to future natural gas prices: (1) longer term trends in gas prices due to supply and demand shocks, and (2) within the year (seasonality) price trends. The uncertainty in long term gas price trends and the seasonality trends is widely recognized.

In general, there is significant historical data from which one can sample actual seasonality price trends. However in regards to long term trends, historical market price data is less useful to the extent that there may not be sufficient liquid forward markets. In lieu of robust forwards market data, the empirical distribution of natural gas price forecast error can be used. For example, the Energy Information Administration ("EIA") produces projections of energy supply and demand, as well as fuel prices, each year in the Annual Energy Outlook ("AEO"). Each year since 1982, EIA's Office of Energy Analysis has produced a comparison between realized ("actual") fuel prices and the Reference case projections included in previous editions of the AEO. With this data, the natural gas price forecast error can be derived based on different timeframes. For example, in the AEO issued in the year 2000 EIA published a gas price outlook through 2020. In 2001, we can derive the "one-year ahead" forecast error by comparing the 2001 forecast gas price from 2000 AEO against the actual gas price in 2001. Furthermore, in 2005, we can derive the "five-year ahead" forecast error by comparing the 2005 forecast gas price from 2000 AEO against the actual gas price in 2005. Taking one step further, in 2010, we can derive the "ten-year ahead" forecast error by comparing the 2010 forecast gas price from 2000 AEO against the actual gas price in 2010. By looking at the back issues of AEO and the historical prices, we have multiple data points for price forecast error for different time frame. We then apply the forecast error on the baseline forecast to derive different annual gas assumptions.

In addition to long term trend, the seasonality profile (i.e., the monthly trend), is also identified as a key variable. The seasonality profile is independent from the long term trend. While the supply-demand shocks drive the long term trend, other factors, like weather, transportation congestion, drive the uncertainly for the seasonality profile.

Combining the variation on annual gas trend (using price forecast error methodology) with variation on seasonality, we can create hundreds of gas outlooks in the "scenario space" as described in step three above.

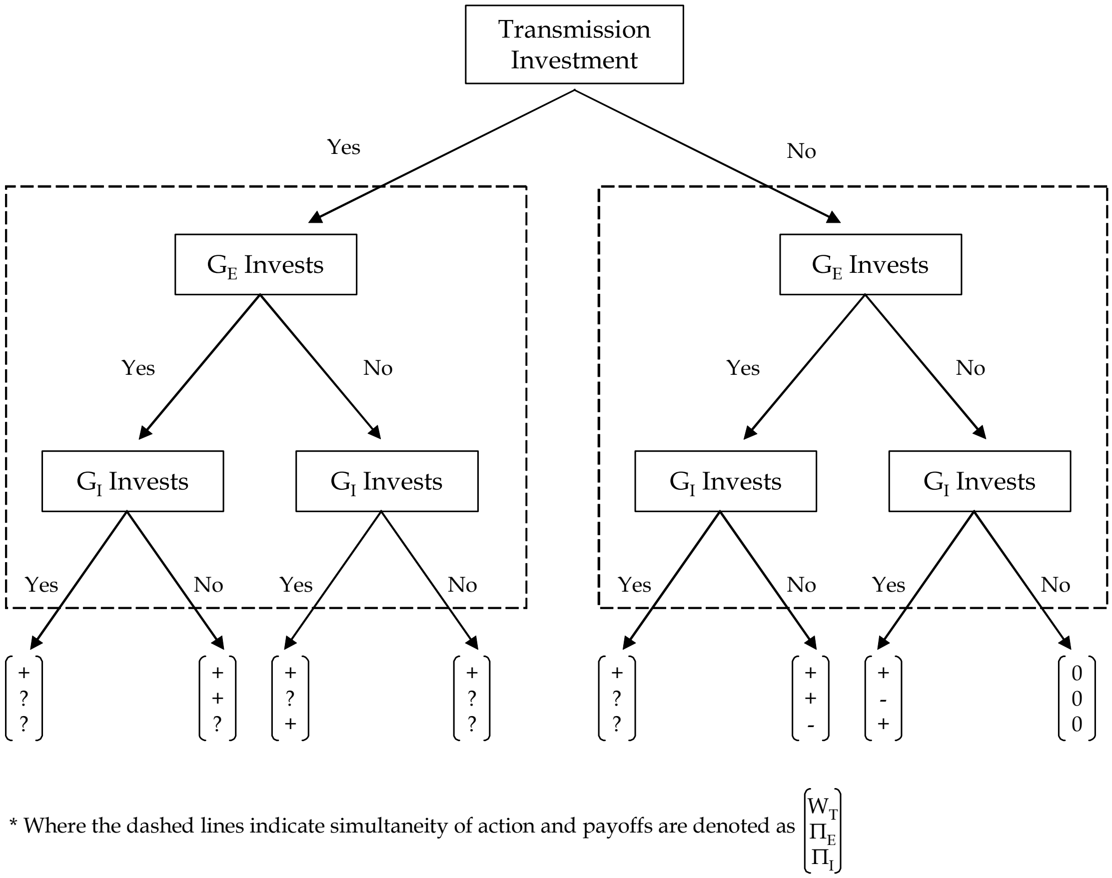
Appendix D: Example of analytical techniques for considering endogeneity of investment decisions

There are many uncertain elements to consider when conducting a cost benefit analysis for a transmission investment project, but by far, the most problematic uncertainty revolves around the inter-dependence of MRAs and transmission assets: investment in one may trigger investment in another (or preclude it). In other words, transmission and MRAs may sometimes be complements and other times, they may be substitutes. The benefits flowing from a transmission investment depend on uncertain future demand for transmission services, and this demand in turn depends on the expected pattern of new non-transmission investment. To determine the optimal transmission investment schedule it is therefore necessary to take account of the incentives to invest in MRAs. As we noted in Chapter 4, markets are complex, comprising many MRA technologies and independent investors and multiple transmission investment opportunities. These complexities can be resolved using backward induction techniques in conjunction with simulation modeling. We describe the backward induction technique in more detail below.

In Chapter 4, we discussed the endogeneity issue resulting from the two way relationship between transmission and generation in a very stylized game theoretic framework where investment decisions are discreet (invest or not invest) and there is only one generation investor and one transmission investor. However, in reality there are many players (for example, multiple generators and transmission projects) considering investments. Taking this analysis one step further, we can consider a situation with three players – a transmission investment, and two generators. The situation with three players (T, G_E, G_I) is best represented by a sequential extensive form game, which is shown in Figure 56.

In the illustration, the Transmission agent (T) moves first by choosing to invest or not to invest. The two generators, having observed T's decision, must then also choose whether or not to invest. Thus the game unfolds sequentially, with T making the first move and G_E and G_I responding to it. In this sense, the two generators know what decision T makes, but they are unaware of the decisions made by one another. The simultaneity of this second round action is represented in the diagram above by the two dashed boxes. In game theoretic terms, these boxes are referred to as the information sets of players G_E and G_I.

Figure 56. Sample sequential investment game with three players



The eight payoff vectors at the bottom of the diagram indicate the expected returns to each player from arriving at each possible final node in the tree. With three players making one yes/no decision each, there are (2^3) or eight possible outcomes. A "+" sign indicates a positive outcome relative to the status quo, a "-"sign indicates a negative outcome, while "?" denotes an indeterminate outcome. In the rightmost final node of the tree in which no player invests, the outcome for each player is "0", indicating no change from the status quo.

The standard way to solve an extensive form game like the one above is by way of backward induction. For T, which we have modeled as having the first mover advantage, this equates to starting at each final node in the tree and figuring out what moves will unfold if they force the two generators down one side of the tree or the other. Based on T's beliefs about the way the generators will react, they can choose whether they are likely to yield the greatest benefit from investing now or delaying until a subsequent period.

Another slightly more intuitive method of solving these games is to translate the extensive form representation in Figure 56 into a 'normal' or 'strategic' form representation. This is shown in Figure 57 below.

Figure 57. Recasting the extensive form game into a 'normal' form representation

		G_E	
		Invest	Not Invest
G_I	Invest	+, ?, ?	+, ?, +
	Not Invest	+, +, -	+, ?, -

With T. Investment

		G_E	
		Invest	Not Invest
G_I	Invest	+, ?, ?	+, -, +
	Not Invest	+, +, -	0, 0, 0

Without T. Investment

As in Figure 56, T makes the first move by deciding whether or not to invest. This decision essentially places the generators in one of these two matrices. Having observed T's move, and given the common assumption that every player knows the entire structure and payoffs of the game, G_E and G_I now must optimize their own outcome (given their expectations about each other moves). As in the extensive form representation, "+" indicates a positive outcome, "-" a negative outcome, and "?" an ambiguous one.

By way of example, suppose that T chooses not to invest and hence the game resides in the right-hand matrix in Figure 57 above. Consider the choices facing player G_E (whose payoffs are the middle symbol; G_I's payoffs are on the right and T's payoffs are noted on the left). The situation for G_I is fairly symmetric and so is not discussed here.

If G_E chooses to invest, he faces a positive outcome if G_I does not invest and an ambiguous one otherwise. Conversely, if he chooses not to invest, his outcome is negative if G_I invests and unchanged otherwise. Thus G_E's optimal choice depends on the move made by G_I. Since G_E's optimal choice depends on the choices of other players, we say that his strategy is 'mixed.' If his optimal choice was independent of the other players, we say that this player has a 'pure strategy'.[159]

With mixed-strategy normal form games, each player is said to have a probability distribution over their available courses of action. For each possible course of action, they assign a probability of taking it. With only two moves per "player" (i.e., "player" refers to transmission or generation investor), this amounts to a probability (say, *p*) of investing and a probability of

159 Pure strategies are rarely observed in real-world examples because they imply no dynamic response or interdependency between the players.

(1-*p*) of not investing. When each of the three players has such a distribution over their action sets, the payoffs to each player at each final node in the tree can be expressed in terms of these probabilities. The solution to the game is then found by simultaneously maximizing the return to each market participant and solving for their corresponding probabilities.

Let us now illustrate this point using Figure 58, which considers the hypothetical payoffs (benefits) to a transmission and generation investor, contingent on each other's actions. This format is an abstraction of a classic game theory two-player, two-strategy game in which both players move simultaneously.

Figure 58. Sample of the 'endogeneity' problem between transmission and generation investment using a stylized game theory

		Transmission	
		Invest	Not invest
Generation	Invest	**14,5**	**8,3**
	Not invest	0,2	5,7

Suppose that:

- player 1 plays invest with probability p and not invest with probability (1-p)
- player 2 plays invest with probability q and not invest with probability (1-q)

The returns to each player (which they both seek to maximize for themselves) can then be expressed as:

$$\Pi_1 = p(10q + 0(1-q)) + (1-p)(8q + 5(1-q))$$

$$\Pi_2 = q(5p + 3(1-p)) + (1-q)(2p + 7(1-p))$$

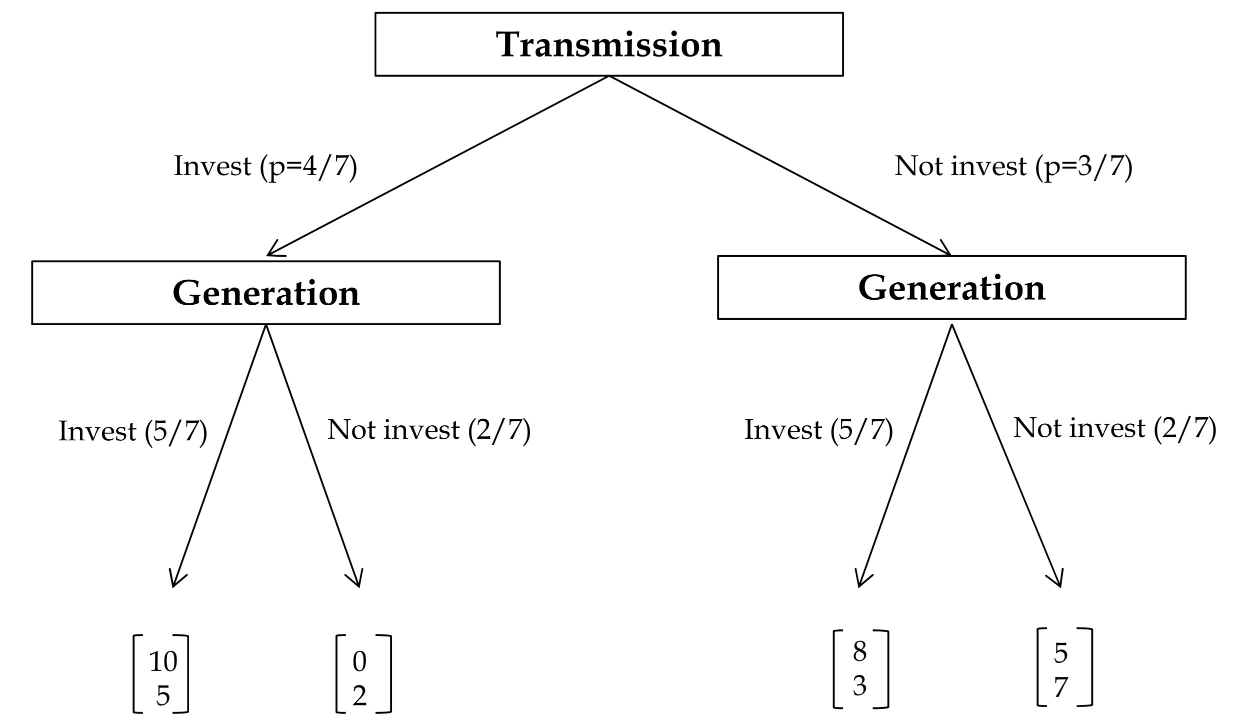
Differentiating each equation with respect to each players own probability and setting equal to 0 yields the following simultaneous equations.

$$\Pi_1' = 7q - 5 = 0$$

$$\Pi_2' = 7p - 4 = 0$$

The mixed-strategy solution is thus player 1 plays invest with probability 4/7 and not invest with probability 3/7, while player 2 plays invest with probability 5/7 and not invest with probability 2/7. These results can then be appended to the extensive form representation of the game to show the probability of arriving at each final node in the tree. The extensive form representation of the game is thus given in Figure 59.

Figure 59. Solution to sample "endogeneity" problem between different market participants



The expected payoff to each player is then just the probability-weighted outcomes under each final node. Returning to Figure 56, since each player in the game is assumed to know the entire *structure* of the game and its payoffs, the method above can be used by T to predict the probabilities that the generators will invest (or not) on both sides of the decision tree (one side corresponding to investment by T and the other corresponding to no investment by T). Coupled with its first-mover advantage, this allows T to derive its expected outcomes on both sides of the tree, effectively reducing the "invest now" or "delay" decision to a maximization of expected returns (which are readily calculable).

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