Henrietta de Veer
Chair, Policy/Regulatory Committee
Northeast Clean Heat and Power Initiative
PO Box 1000
New York, NY 10016
hdeveer@adaptiveenergystrategies.com

September 10, 2015

VIA ELECTRONIC MAIL

Hon. Kathleen H. Burgess
New York Public Service Commission
Three Empire State Plaza
Albany, New York 12223-1350

Re: In the Matter of Case 14-M-0101 Proceeding on the Staff White Paper on Benefit-Cost Analysis in the Reforming the Energy Vision Proceeding

Dear Secretary Burgess:

The Northeast Clean Heat and Power Initiative ("NECHPI") hereby submits for filing its attached reply comments to the New York State Department of Public Service regarding the above-referenced Case 14-M-0101 in the Matter of the Staff White Paper on the Benefit-Cost Analysis in the Reforming the Energy Vision Proceeding.

These comments are authored by Henrietta de Veer, Ph.D., Managing Partner of Adaptive Energy Strategies LLC and Chair of NECHPI's Policy/Regulatory Committee and incorporate the inputs and reviews of the Regulatory/Policy Committee, which includes Ruben Brown, M.A.L.D, and Matt Cinadr, P.E. and the Executive Committee of NECHPI, which represents more than fifteen major companies and organizations in the Combined Heat and Power ("CHP") industry. Various members of NECHPI, including Ms. de Veer (Managing Partner of Adaptive Energy Strategies LLC); Ruben Brown (CEO, The E Cubed Company, LLC); Matt Cinadr (Senior Associate, The E Cubed Company, LLC); and Herbert Dwyer (President, ASI Energy, Inc.) actively participated in many of the committees in Track I of the proceedings, and will continue to be directly involved in Track II initiatives and activities. Two NECHPI Board members, David Ahrens (Managing Director, Energy Spectrum) and Tom Bourgeois (Deputy Director, Pace Energy & Climate Center and Director, U.S. DOE's Northeast CHP Technical Assistance Partnership) are members of the MDPT working group. As a matter of information, Ms. de Veer, Mr. Brown and Mr. Cinadr represent NECHPI on NYISO's Business Issues Committee, Management Committee, and Market Operations Committee, respectively.

Respectfully submitted,

Henrietta de Veer

Henrietta de Veer
Chair, Regulatory/Policy Committee

CASE 14-M-0101 – Reply Comments on the Staff Benefit-Cost Analysis Framework White Paper, filed July 1, 2015, in the Reforming the Energy Vision Proceeding

REPLY COMMENTS
OF
NORTHEAST CLEAN HEAT AND POWER INITIATIVE ("NECHPI")

September 10, 2015

Northeast Clean Heat and Power Initiative
PO Box 1000
New York, NY 10016
hdeveer@adaptiveenergystrategies.com

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REPLY COMMENTS OF NORTHEAST CLEAN HEAT AND POWER INITIATIVE ("NECHPI")

September 10, 2015

Northeast Clean Heat and Power Initiative (NECHPI) is a 501(c)(6) business league functioning primarily in the eight northeastern states of New York, New Jersey, Connecticut, Rhode Island, Massachusetts, Vermont, New Hampshire and Maine. Until 2012, it was simply a voluntary association. To be exempt, a business league's activities must be devoted to improving business conditions of one or more lines of business as distinguished from performing particular services for individual persons. It must be shown that the conditions of a particular trade or the interests of the community will be advanced. NECHPI's comments submitted here adhere to this standard.

Executive Summary

General Recommendations

- The BCAF is critical for the successful implementation of REV and all of its component proceedings. The issue is serious and could have long-term negative financial, economic and related consequences if not developed and implemented appropriately. In addition, the BCAF is not linked concretely to REV objectives and the State's clean-energy goals. In NECHPI's estimation as well as in the estimation of other active parties, there is no reason to rush head-long into implementing an inadequate BCAF, in many cases based on traditional approaches not applicable to REV nor in the best interests of State citizens and ratepayers. As New York City in its comments states: "**A matter as important as the BCA framework for an entire new construct of the electric industry in New York warrants far more process and input from interested parties than two rounds of public comment spread over a short span of time and in which requests for additional time were denied.**"

- Locational and temporal values are clearly critical to the success of REV, and yet the BCAF relies exclusively on system-wide average values. Staff does not confront this issue head-on, and avoids addressing the fundamental requirement for circuit-level information to drive the valuing of DER costs and benefits. Without these locational and temporal values in the BCAF, the chances not only of REV success but also of achieving clean-energy goals will be low.

- There are missing costs and benefits too numerous to list, but their absence will lead to skewed results, favoring certain outcomes over others. This will require a collaborative stakeholder process to rigorously vet the components of the BCAF.

- The cost-effectiveness tests themselves are traditional models developed years ago to evaluate energy efficiency programs in an era when utilities were the only entities funding energy efficiency. There are new approaches being developed, including in California where the tests were developed and applied in the first place. There is also emerging an approach based on the Resource Valuation Framework, which should be considered seriously as a framework for developing a new approach for cost-effectiveness tests tailored to specific DERs, not just energy efficiency.

- It is extremely unclear if the CBAF will be used for both project/program/portfolio screening and compensation mechanisms/pricing decisions. Much rides on this as many DER developers are looking hopefully on the creation of revenue streams from REV. Given that "out-of-market" financial support mechanisms are disappearing quickly, the Commission has to get this right or the New York DER market will collapse and investors will pull out.

- There are numerous issues discussed by active parties; however, it is clear that they are complex, critical and far-reaching. NECHPI is supportive of the vision, but simply wishing for positive outcomes will not get the State where it needs to be. The issues surrounding GHG emissions are a case in point. NECHPI believes that the proposed approaches are overly complicated and that there are "low-hanging-fruit" options which could drive lower emissions than the ones proposed. This is not to say that system-wide valuing of emissions is not important; it is simply that an over-reliance on the approach will not get the State where it needs to be.

- There seems to be significant reluctance in New York to mandate utilities to adopt certain approaches, whether it is for common methodologies and toolsets, preferred resource loading orders, and the like. States which have been most successful have mandated key objectives, and what is required to achieve those objectives. The State's clean-energy goals for GHG emissions reductions, renewables as a % of retail supply, and energy-efficiency savings are wonderful on paper but it is unclear how the State will achieve those goals as well as REV objectives of "market animation," customer engagement, system efficiency, etc. without clear and specific mandates for achieving them. We need to get beyond the "wish and the hope" stage.

Recommendations on Required Foundational Work on State and Utility Energy Resource Plans, Mandated Common Methodologies and Tool Sets, and State Preferred-Resource Loading Order

- Thus, NECHPI notes the importance of the development and adoption of transparent, standardized, replicable and scalable methodologies, procedures, processes and associated documentation in valuing fully all of the costs and benefits of distributed energy resources ("DERs") whose values should be based on timing, location, flexibility, predictability, reliability, availability and controllability of the resource. Then, these developed methodologies should be consistently applied to all DERs and allow any resource to participate in programs at the level appropriate to their capabilities and attributes. There should be an assurance of "resource-neutral" markets so that each DER is able to compete to fulfill specific grid and load requirements if it is capable of doing so. This approach enables stakeholders to assess the validity, fairness, applicability and internal consistency of the assumptions used in a BCAF. <u>The current proposed BCAF does not provide NECHPI with the assurance that it will be resource-neutral and ensure all of the benefits and costs of all DERs are fully incorporated.</u>

- <u>NECHPI believes that EPRI's CBA framework, coupled with the use of the California utility Distributed Resource Plans as a template and roadmaps for their own DSIPs (based on the EPRI model), provide utilities a standardized and transparent bottoms-up approach to all of the elements required for robust, systematic, integrated distributed-resource planning. (Please see Appendix for an overview of EPRI's Integrated Grid CBAF.) The advantages are numerous:</u>

  - <u>**EPRI thus seeks a common ground for a CBAF for all stakeholders. The framework is meant to be the same regardless of the electric system, state and local policy goals, utility business practices, and regulatory oversight parameters and whose outputs can be used in any cost-effectiveness screening processes.**</u> EPRI maintains that "the benefit-cost framework for the Integrated Grid establishes this sound engineering and economic foundation; from it, multiple stakeholder perspectives can be examined upon it." Critical to using new analytic tools for DER assessment is an understanding of the perspectives of all parties involved and that, while reconciling these different perspectives may be difficult, the chances of success are improved if all can share an accurate understanding of the physical and economic requirements for grid integration. In addition, NECHPI believes that adopting this foundational approach will alleviate many of the issues surrounding the current BCAF articulated by both the utilities and active parties.

- The approach establishes real, engineering- and economic-driven values to the circuit level, and traces all of their causes and effects through the distribution, transmission and bulk-power systems to remove double-counting and to provide the ability to update values dynamically as the DERs scale on and across circuits and substations through the distribution system. The approach also has the advantage of providing a structure for actual measurements of performance by technology or combinations of technologies as well as of GHG and other criteria-pollutant emissions. See Appendix H for a discussion of recent breakthroughs in the integration at the circuit level of real-time emissions and grid data analysis that is able to turn price-responsive assets into emissions-responsive assets.

- If the distribution planning process starts with baselines down to the circuit level and builds out from there, this approach changes the whole conversation around the CBAF and the numerous issues pointed out in various active-party comments.

- EPRI's BCAF provides the concrete basis for the implementation of the REV market-driven vision based on locational and temporal values down to the circuit level. NECHPI argues that the proposed, fairly traditional approach to the proposed BCAF entails numerous compromises because of the attempt to adopt "gross," system-wide values which can never be used to establish circuit-level locational and temporal net benefits, which as EPRI notes repeatedly, vary widely among and between circuits (even along line segments of circuits).

- It alleviates concerns in cost-effectiveness tests about the complete symmetry of costs and benefits since all values associated with them are established from the ground up.

- It allows for transparent and standardized comparisons of DER solutions with traditional utility investments for solving specific grid issues locally and across the distribution system and enables utilities, the Commission and stakeholders to peel the "financial onion" down to all of its component parts. This will allow the alignment of existing utility capital-expenditure programs (including grid modernization and storm hardening) funded under current general rate cases (particularly expenditures that need to be made regardless of DER integration and scale-up), to be separated from existing, new and proposed DER programs and grid expenditure programs (proposed and existing) which enable the scale-up of DERs on the distribution system.

- The approach allows for the streamlining and full integration of DER interconnection processes into a utility's distribution-planning processes. By having detailed knowledge of each circuit, the utility can enable more efficient and cost-effective interconnections across the grid. (It should also be noted that it can identify those circuits where DER interconnection is uneconomic because the costs to "enable" DER interconnections are higher than the benefits DERs would provide. Again, this is advantage of the bottoms-up approach in being able to analyze, assess and prioritize circuits for DER integration.)

- It provides the framework for integrating with transmission and NYISO long-term planning functions, which will include an analysis of the effects of grid-tied DERs, most particularly large-scale renewables, as well as behind-the-meter resources, on the transmission and bulk-power systems.

- The outputs of the EPRI BCA provide common inputs to the various tests to be used in screening utility DER programs and programs for cost-effectiveness. While EPRI, in its primary analytic framework, only includes those costs that can be recovered through its revenue requirements, its "accommodation" methodology allows for the incorporation of costs and benefits not priced by the market or administratively (and therefore, not included in a utility's revenue requirements.) EPRI's view is that the utility's perspective is still essential because DER accommodation will require the utilities to incur costs to realize benefits.

- NECHPI believes that a considerable amount of foundational work still needs to be undertaken if the State is to successfully implement REV and align all of the various proceedings, including the Large-scale Renewables Program; if the utilities are able to meet various State and REV clean-energy mandates; and if the State is to achieve its clean-energy goals. This foundational work will also need to be done if a Cost-Benefit Analysis Framework is to be implemented successfully. There need to be baselines established in order for metrics to be selected and used to measure the success of various programs, projects and other initiatives, a necessary condition to measuring, validating and valuing progress toward specified clean-energy goals and objectives. Given the postponement of the utility DSIP filings to June 30, 2016, there is sufficient time now to undertake (or at least start the process pf undertaking) all of the foundational work necessary to ensure the successful implementation of REV initiatives and programs.

- The Commission should seriously consider mandating a preferred-resource loading order, which specifies that utilities must first consider such DERs as Energy Efficiency, Demand Response, and Distributed Generation (both renewables and CHP) before making traditional grid investments. NECHPI believes that utility resistance over the integration and scale-up of DERs is sufficient, at least over the near to intermediate term, to warrant consideration of such an approach.

- The Commission should also consider mandating certain common methodologies and tool sets to which all utilities are required to adhere. These should include a common BCA framework (e.g., based on EPRI's Integrated Grid BCAF, discussed in detail further in the document); an agreed-upon locational net benefit methodology ("LNBM") using a tool such as Energy and Environmental Economics' ("E3") Distributed Energy Resource Avoided Cost ("DERAC") calculator, modified to include a variety of locational costs and benefits; a methodology for analyzing circuit capabilities within agreed-upon limits among the utilities; and power-system modeling software. There are numerous advantages to the approach, not the least of which is that **NECHPI believes that the EPRI CBAF is the only framework fully supportive of and compliant with REV objectives**. EPRI's BCAF provides the concrete basis for the implementation of the REV market-driven vision based on locational and temporal values down to the circuit level. NECHPI argues that the proposed, fairly traditional approach to the BCAF entails numerous compromises because of the attempt to adopt "gross," system-wide values which can never be used to establish circuit-level locational and temporal net benefits, which, as EPRI notes repeatedly, vary widely among and between circuits (even along line segments of circuits).

Specific Concerns on the Proposed Benefit-Cost Analysis Framework

- It is clear from the comments in the current BCAF proceeding that active parties are very concerned about how and through what means the CBAF will apply (or will be able to be applied) to the development of new tariffs. There has been little to no discussion of whether the DER cost-effectiveness screening tests will be used simply for screening purposes or for prioritizing project, programs and/or portfolios of programs or for establishing compensation mechanisms. This is a major and critical issue. These issues should be addressed carefully and explicitly in an open, transparent collaborative forum.

- Because of the incompleteness of the proposed BCAF and the many issues not addressed clearly or consistently, which is clearly evidenced by active party comments to the proposed BCAF, NECHPI strongly recommends that the Commission establish a collaborative stakeholder process to develop a robust CBAF that will be able to support REV objectives and enable the achievement of State clean-energy goals.

- In addition, NECHPI recommends that the Commission consider initiating a collaborative process for developing a framework for integrating the various proceedings to ensure that any overlaps, inconsistencies and even contradictory elements are removed and that utility, DER developer and other stakeholder efforts are not duplicated unnecessarily. NECHPI believes that such a working group can set the stage for the full integration and deployment of distributed energy resources that provide optimal customer and system benefits while enables the State to achieve its climate and other objectives and for integrating the multiple proceedings already in place in Track I and likely to proliferate during Track II.

- NYISO's observations, coupled with the analyses provided by NECHPI in Appendix F on the effects of variable energy resources on wholesale markets, would indicate that the issue is serious enough to warrant a collaborative working group to discuss the many issues surrounding the scale-up of distributed energy resources, including large-scale renewables, and their effects on wholesale markets.

- NECHPI believes that the Commission needs to address utility resistance to the issues surrounding disclosure of circuit-level information. This is fundamental to the implementation of the REV vision if it is to be successful. In some sense, this is a cultural issue since it is clear that other utilities, most particularly in California, provide significant amounts of circuit-level information used not only in their own internal planning processes but also to inform DER developers of the optimal locations for deployment. It needs to fully explained why it is that California utilities, HECO in Hawaii, and even Massachusetts utilities in the monthly disclosure and updating of detailed interconnection queue information on a circuit by circuit basis why New York utilities are unable/unwilling to do so. This is a priority issue which needs to be addressed over the short term.

- NECHPI believes, however, that if the Commission adopts a societal cost-effectiveness screening test, coupled with a societal discount rate, with the State needing substantial levels of private-sector financial support to achieve its goals, there will be a wide gap between the outcomes from the cost-effectiveness screening tests and those based on private-sector, risk-adjusted returns, which will produce very different results. The New York Green Bank could play a fundamental role in filling that gap.

- In NECHPI's estimation, many other key "local" values need to be clarified and more delineated, specifically incorporated into a BCAF and vetted in a collaborative stakeholder working group. These values include: resiliency, reliability, controllability, availability, and predictability. The working group should also evaluate the emerging concept of "distribution marginal price" under development currently and being tested at a number of utilities in California and elsewhere.

- It is important to have the localized and temporal costs and benefits associated with DERs clarified and those associated with microgrids and hybrid systems specified and included in the final BCAF. A clear indication is the puzzling lack of discussion in the CBAF on values associated with the key REV and State clean-energy goals of resiliency and reliability. These are critically important values to CHP on a stand-alone basis as well as part of microgrids and district energy systems, and should be well-articulated and supported values in the CBAF.

Specific Concerns of the CHP Community on the Proposed CBAF

- Entirely missing from the CBAF are values associated with thermal energy, a key value for CHP, both renewables- and gas-fired, as well as other distributed resources that provide thermal value such as renewables heating and cooling. The unique set of both electricity and thermal benefits are not reflected in the Staff's list of costs and benefits, which are focused exclusively on the electric grid. NECHPI requests that the Commission urge the Staff to include in the CBAF costs and benefits associated with heating and cooling and their integration with the electric grid.

- REV itself has been entirely focused on the electric grid, so it is not surprising that there is an absence of the benefits associated with thermal energy. However, NECHPI has pointed out in numerous of its other comments throughout this proceeding that there is considerable empirical evidence that the State will not achieve many of its clean-energy goals, most particularly projected renewable energy penetration levels and GHG emissions reductions, without incorporating explicitly the integration of electricity, gas, heating and cooling into the CBAF.

- In terms of energy-intensity reductions, while New York State does support output-based emission standards, they have not been incorporated into the CBAF nor has they even been mentioned. Not using output-based emissions standards in the CBAF puts CHP in a highly disadvantageous position since it is one of the key means to "level the playing field" and allow CHP to provide the multiple benefits it is able to provide to both the grid and loads while reducing significantly GHG emissions levels as well as toxic criteria pollutants. See Appendix E for a comparison of a 10 MW CHP plant to a 10 MW solar PV and a 10 MW wind plant. It graphically demonstrates CHP's ability to provide substantial levels of highly efficient electrical and thermal energy while greatly reducing GHG emissions levels per unit of production.

- NECHPI has significant concerns about the final Generic Environmental Impact Statement ("GEIS") and its implications for CHP's role in REV and in the emerging 21st century energy ecosystem. Firstly, the GEIS employs a different set of methodologies for calculating DER values and environmental impacts than proposed in the CBAF. More importantly, the final GEIS is focused on a single measurement of peak-load reduction to establish environmental impact levels. At one point in the document, the GEIS states that "on average, across all potential scenarios, CHP systems result in no net reduction in emissions."[1] NECHPI strongly disagrees with the results, which can be amply

[1] *Final Generic Environmental Impact State in Case 14-M-0101 – Reforming the Energy Vision and Case 14-M-0094 – Clean Energy Fund*, prepared by Industrial Economics, Incorporated and Optimal Energy, Incorporated for NYSERDA, February 6, 2015

supported about all of the empirical analyses and approaches discussed in the current comments. Thus, NECHPI strongly urges the Commission to direct Staff to include the range of benefits discussed in these comments in the proposed Cost Benefit Analysis Framework.

- The Staff should also be directed to consider adopting a rigorous methodology for estimating generation fuel displacement by avoided use of grid electricity by the array of distributed energy resources. NECHPI recommends that New York State through the CBAF process investigate a reasonable and consistent fuel-displacement accounting method that can be used for renewable generation, CHP, demand response, energy efficiency and other DERs such as energy storage and EVs in order to ensure that both the costs and benefits of various technologies are being properly analyzed and valued.

NECHPI Reply Comments on Active Party Comments on the CBAF

The following are NECHPI's summaries on various active parties' comments. More detail is provided in Appendix I. The following are primarily focused on those comments with which NECHPI agrees.

New York City

- The Staff White Paper needs further development and the Commission should limit implementation steps related to REV to demonstration projects.
- There should be a single, state-wide BCAF with common analytics and the manner in which the BCA is performed and each cost and benefit treated should be uniform statewide. Additional locational and project-specific costs and benefits should also be included.
- NECHPI could not agree more with the following statement from the City of New York: **"A matter as important as the BCA framework for an entire new construct of the electric industry in New York warrants far more process and input from interested parties than two rounds of public comment spread over a short span of time (and in which requests for additional time were denied."**
- The CBAF needs to incorporate the proposed duration of potential benefits in order to accurately measure them.
- The inclusion of wholesale prices is speculative at best.
- Issues surrounding valuing carbon are best addressed via a collaborative process.

New York Geothermal Energy Association

- There is a complete "siloing" of electric and thermal issues.
- It is crucial to clarify the role of thermal measures in the BCAF, including how benefits and costs will be evaluated in a fuel-switching context.
- "Unless an accepted means of establishing and projecting externalities for fuel consumption in New York's buildings is established, the benefit-cost analysis framework will remain incomplete and of questionable utility."

Peak Power

- By including a realistic and dynamic assessment of the drivers of DER project costs, especially the costs and tenor of project capital and the crucial links back to revenue certainty and program uptake and administrative costs, the BCA will be more accurate and create more cost-effective programs.
- The BCA should work toward "universal materiality standards." There is little explanation in the white paper of why some benefits and costs are emphasized while others are simplified away.

- "Discount rates and investment horizons vary dramatically between society, utility and DER provider; conflating all three creates unrealistic expectations and wasted or insufficient resources in incentivizing and managing DER. Oversimplifying discount rates into a single input will create counterproductive distortion between BCA-level planning and the real world."
- There are three distinct layers of evaluation from value to price signal to DER response, and different discount rates should be applied at each step.
- Using a single, standard utility WACC (or a societal discount rate) for all three steps ignores program- and project-specific risks: technology risk, site control issues, single-decision regulatory changes, etc. that accompany specific projects therein.
- The risks of oversimplifying with a single discount rate are especially market in less mature markets such as demand response.

AEE Institute

- There needs to be more detail on how different benefit-cost tests will be used in decision-making, investment, planning and tariff development.
- Staff's approach is quite conventional and should be more innovative.
- A fully transparent methodology and associated assumptions used to calculate values should be uniform across the state and established through a collaborative statewide process.
- The BCA needs to undertake scenario analyses relative to uncertainty of various inputs.
- Levels of risk by technology and project must be accounted for.
- Benefits and costs should be actual and measured, not based on other markets developed for different purposes.
- AEEI supports the use of the Resource Value Framework.

Association for Energy Affordability

- Values for combination DERs need to be included.
- Omitting some benefits leads to computational bias in benefit-cost ratios and, as a result, a bias in decision-making using those ratios. Benefits and costs must be symmetrical.

Pace Energy and Environment Center

- Utilities should collaborate on developing a common methodology.
- BCAF development should be a continuing process rather than a single Commission decision.
- The White Paper should address how the BCAF will be applied in the process of implementation.
- There is insufficient guidance by which the BCAF will be used to inform distribution planning, the valuing of behind-the-meter resources and the adapting to changing technology markets.
- While the SCT should be the primary test employed, by applying a different lens of analysis to different stages of decision-making, the BCA process as a whole could capitalize on the strengths of each test.

Clean Coalition

- The BCAF should be developed with a degree of specificity required to derive market prices and be consistently applied to different scales and types of investments and tariffs.
- Clean Coalition recommends the option-value approach to valuing DERs, which recognizes variability in different components and analyzes the impact of co-variance amongst key components.

- The functions and services provided to the electric grid and the methods for establishing the value of these functions should be technology-agnostic and broadly applicable to any resource in relation to its performance and location.
- The California Distributed Resource Plan proceeding should be used to establish methodologies for utilities to plan for higher penetrations of DERs within the distribution grid.
- Adopted BCA methods should integrate interconnection practices.

Multiple Intervenors

- There are many missing cost components.
- Staff is proposing that only certain externalities are incorporated into the BCAF, which is problematic.
- If the Commission incorporates environmental externalities into the BCAF and they are inaccurately high, it could lead to decisions that increase costs to customers and exacerbate the State's already-substantial, competitive disadvantage vis-à-vis other states with respect to energy costs.

NY-BEST

- The Staff provides no guidance on how the three cost-effectiveness tests relate to each other or how they will be weighted relative to each other.
- There needs to be coordination with NYISO.
- BCAF should include sensitivity analyses for load growth and mechanisms to value flexibility, optionality and resiliency.
- There are numerous missing benefits of importance to distributed resources.
- The utilities need to provide significant circuit-level information in order for REV to be implemented successfully.

Exelon Companies

- The BCAF needs to be robust to account for a wide range of existing utility investments and not unduly favor DERs based on speculative or inflated benefits or on ignoring real costs and risks.
- The BCAF needs to account for externalities but exercise common sense, focus on those directly related to the energy and policy objectives of REV and are transparent, verifiable and quantifiable, recognize the significant costs associated with DER grid enablement.
- The BCAF needs to work within and not compromise existing competitive market structures.
- The BCAF must be complementary and integrative of and linked to all REV proceedings.
- The BCAF should be realistic, consistent and unbiased.
- The BCAF must be implemented workable.
- While the BCA properly recognizes GHG externalities, it should not artificially create preferences of how to achieve GHG reductions.
- The Commission needs to "get it right," as errors will lead to wasted capital, increased costs and lost opportunities to deliver actual value.

Institute for Policy Integrity

- IPI differentiates between resource-allocation decisions (utility investments in the DSP platform, DER procurements through selective processes and energy efficiency programs) and pricing decisions (tariffs). The BCAF should differentiate between resource-allocation decisions, which are reasonably straight-forward, and pricing decision. The BCA is intended to calculate the total costs and benefits of a project; it is not intended to establish the marginal costs and thus, should not be used to determine efficient price signals.

- Clearer guidance is needed on how exactly the BCA would be used in pricing decisions, the distinction between values that would be used for monetization in the BCA and values that would be used in tariffs, and the necessity of separate marginal cost studies is needed.
- The BCA needs to include "robustness checks," scenario and sensitivity analyses, and a variety of risk-mitigation strategies and methodologies.
- Data granularity is particularly significant if the Commission uses the BCAF as a basis for DER tariffs. For example, the analysis of both forecasted resource savings and the quantity of avoided emissions should consider the effects of time granularity.
- If temporal dimensions are not taken into account, DERs will be rewarded based on the same average quantity of avoided emissions, leading to inefficient allocation among different investment alternatives.

Joint Utilities

- JUs are focused on creating a level playing field between DERs and traditional utility investment options.
- JUs have proposed a new test, the Distribution Cost Test ("DCT"), which is identical to the Program Administrator Cost ("PAC") Test except that it does not directly include wholesale market costs and benefits.
- JUs support the continuance of the existing BCA for existing energy efficiency programs, provided that the cost-recovery provisions remain in place.
- The quantification of benefits under BCA tests should not be a proxy for establishing payments to DER participants. Benefits quantified under BCA should not be presumed to be, or confused with, revenues a DER provider will receive.
- Great care must be taken so that the BCA avoids a bias toward any particular technology or type of solution.
- Artificially stabilizing the environment for DER through subsidies or other market distortions that insulate it from any inherent and economically fundamental risks and uncertainties is not an appropriate principle for the BCAF and may result in decisions that do not benefit customers.
- JUs support the need for a statewide transparent and consistent BCA approach. There needs to be an evaluation platform for all resources so that REV-related decisions are made in an objective and fact-based manner to benefit all New York energy consumers.
- The BCAF should be supported by consistent inputs and assumptions so that targets set for REV metrics are based on robust and accurate data.
- If a proxy portfolio is cost-effective on the basis of the DCT, then the utility would formally solicit DER alternatives from the market and apply the DCT when evaluating DER proposals against one another and against the traditional distribution system alternative. To the extent that multiple portfolios are cost-effective, the JUs propose to optimize and ultimately select the third-party alternative(s) based on performance under the other three BCA tests.
- BCA tests are appropriate tools only to compare solutions that offer equivalent functionality or optionality to the grid, that is, that can reasonably substitute for the specific traditional investments at those specific locations with no degradation of system or circuit performance, including power quality, reliability, safety and resilience.
- BCA tests are not applicable to demonstration projects, research and development, promotional and outreach activities related to REV, customer portals, advanced metering infrastructure or equivalent, distribution automation and other grid modernization investments, technology platform investments, software and systems required to develop and implement DSP markets, and other DSIP supporting investments.

- Introducing the additional externality value of GHG emissions into the BCAF will simply raise electricity costs to customers without any benefit of reducing emissions.

NECHPI General Reply Comments to the Proposed CBAF

General

- Issues surrounding higher levels of renewables integration should be addressed over the short term. The proposed CBAF does not address the costs and benefits associated with renewables integration, including values associated with flexibility, resiliency and reliability, major missing pieces to a robust CBAF, particularly given REV objectives and State clean-energy goals. The Commission has the opportunity to put in place policies and requirements to ensure that the unintended consequences of the rapid scale-up of renewables as happened in Germany and California do not happen in New York State. Planning for renewables integration, both in-front-of and behind-the-meter, should begin now. It is impossible to see how the level of renewables penetration, combined with the projected GHG reductions, will be achieved without incorporating these key values into the CBAF. Please see Appendices C (combining renewables with flexible DER resources such as energy storage and CHP, with case studies from Germany and California) and D (the effects of the scale-up of variable energy resources on wholesale markets) for further discussion.

- NECHPI has stated in numerous comments throughout these proceedings that that there is clear indication that many stakeholders believe a 100% renewables future is viable over the relatively short term and will be the path to a low-carbon future. This is demonstrably not the case, and without honest discussion and rigorous analysis of the subject, the State will not develop reasonable, achievable and cost-effective plans with a strong chance of success to meet its goals. NECHPI acknowledges that CHP represents only one piece of the ultimate solution, but if the State hopes to achieve its very ambitious goals, stakeholders need to step back and evaluate the requirements of a complex power system in transition and how all distributed technologies need to work together to achieve the ultimate goals set forth in the State Energy Plan and various REV proceedings.

- In NECHPI's opinion, there is a now unwarranted simplifying assumption that simply deploying great quantities of large-scale renewables will achieve the State's clean-energy goals. This is demonstrably not the case. Deploying larger and larger quantities of grid-connected renewables does not necessarily reduce GHG emissions levels and lower electricity prices. NECHPI has noted in other filings that, in fact, even after scaling many GWs of renewable resources over the last decade, both Germany and California, as excellent cases in point, have essentially the same levels of GHG emissions and the highest electricity prices ever over the same time period. The indirect effects of high penetration levels of renewables necessitate the use of integration techniques such as energy storage and CHP to provide the flexibility and balancing services to enable much higher levels of renewables while reducing GHG emissions levels. (See Appendix C for detailed discussion.)

- There are numerous REV programs and initiatives already specified and being discussed in various proceedings. However, the details of their budgets, the overlap and/or inter-relationships with existing utility initiatives and capital expenditure programs funded under other Commission authorizations, including general rate cases, and the sources of monies to support both new and existing DER programs are still unclear. NECHPI is highly skeptical that, a part from the financial issue, the State's goals can be met without significantly higher levels of empirical analysis and rigorously applied assumptions for a well-developed State energy resources plan, with detail by resource, for the next 10 years, updated every two years. In addition, if the assumptions used in the CBAF are erroneous, misleading or incomplete, ratepayers could be saddled with supporting large amounts of resources, which could provide to be uneconomic, not effective and/or unproductive.

- REV is generally focused on the scale-up of behind-the-meter distributed-energy resources, with an emphasis on peak-load reduction. However, NECHPI believes this exclusive focus to be a regrettable choice since both behind-the-meter and grid-connected DERs will be key to the ultimate success of REV and for the decarbonization of the State. All REV-related programs, including the proposed BCAF, need to be fully integrated into NYISO bulk-power-system planning and all State and REV clean-energy activities in order to ensure that the State's key objectives are met by 2030.

- There is an entirely different market environment today than 10 years ago, and there is a variety of financial strategies that would be more cost-effective and benefit all stakeholders in the State's clean-energy future than those discussed in the CBAF. NECHPI notes the lack of discussion on the potential role of the New York Green Bank in supporting financing mechanisms for the scale-up and support of distributed-energy resources. There is evidence that private-sector support is strong, and the Green Bank could leverage that support to provide a low-cost means for the State to build its renewable-energy infrastructure without relying on State ratepayers.

- NECHPI believes, however, that if the Commission adopts a societal cost-effectiveness screening test, coupled with a societal discount rate, with the State needing substantial levels of private-sector financial support to achieve its goals, there will be a wide gap between the outcomes from the cost-effectiveness screening tests and those based on private-sector, risk-adjusted returns, which will produce very different results. The New York Green Bank, given its mandate, should be in a position to support this gap with various credit-enhancement approaches and others not yet discussed or on the table. NECHPI is concerned about an overreliance on financial instruments such as YieldCos since there is considerable analysis on the risks associated with YieldCos, particularly in market environments with increasing interest rates.

    - The Green Bank has not yet demonstrated the success of its business model and approach, and while the jury is still out, NECHPI recommends that the Commission continue to evaluate other approaches to financing the scale-up of DERs on a stand-alone basis or in combination with the Green Bank. (As an example, the New York does not have a State PACE Program; rather, it requires county-by-county implementation. It would be an immense benefit to the State if the legislature supported a State Program since it is clear from Connecticut's experience that a statewide program is effective not only for program scaling but also for attracting sources of capital for both short-term project financing as well as the successful securitization of a portfolio of projects. The State has accomplished this through establishing rigorous, industry standards-based benchmarking, monitoring and verification criteria integrated into a financial underwriting platform developed and managed by Sustainable Real Estate Solutions, which has given financial investors confidence in the cost-effectiveness of the program.)

- There is increasing recognition that a portfolio of DERs, combination DERs, hybrid systems and microgrids across the grid will provide the optimal solutions for renewables integration to maximize benefits to both the grid and consumers at lowest cost while maintaining reliability, resiliency and safety and reducing GHG emissions. This portfolio approach provides resource diversity and risk mitigation as DERs are scaled across the distribution, transmission and bulk-power systems. In particular, NECHPI urges the Commission to begin the process as part of the review of the CBAF to focus on the development of the costs and benefits associated with hybrid systems and microgrids. Values associated with microgrids, including black-start and islanding capabilities provided by such DERs as CHP, should be valued and appropriately monetized. This is particularly urgent given that the State, using ratepayer funds, has recently committed to funding feasibility studies for 83 microgrids across the State. Without developing pathways to valuing the benefits of these proposed projects, the State will have wasted considerable monies and DER providers a great deal of resources in efforts that will lead nowhere.

- NECHPI also believes it significant that, in an 8/13/15 Order Instituting Rulemaking, the California Public Utilities Commission expanded its distributed-resource focus to include DERs in front of the meter as well as behind-the-meter and also now includes a focus on hybrid solutions to meet the needs of the grid and customer alike because of the scale-up of variable energy resources on the grid. NECHPI believes that, if the EPRI BCAF is adopted as the baseline approach, coupled with upgraded DER cost-effectiveness tests (see below for discussion), the distinction between behind- and in-front-of-the-meter analyses of DER net benefits becomes moot. They are simply part of the continuum of energy resources able to be controlled and optimized to provide both grid benefits and benefits to loads.

- Using EPRI's framework, the focus of the California utility distributed-resource plans was to take what have been considered more system-wide, average values and modify them to add "localized" benefits to them using the Commission-mandated DERAC tool described previously.

- In NECHPI's estimation, many other key "local" values need to be clarified and more delineated, specifically incorporated into a BCAF and vetted in a collaborative stakeholder working group. These values include: resiliency, reliability, controllability, availability, and predictability. The working group should also evaluate the emerging concept of "distribution marginal price" under development currently and being tested at a number of utilities in California and elsewhere.

- The Commission and the Department of Public Services are fully aware that NYSERDA awarded 83 feasibility studies as part of the NY Prize Community Microgrid Program. Many of the awardees have high expectations of participating in both NYISO and retail markets based on REV initiatives. NYISO is in final development stages of a Behind-the-Meter-Net Generation ("BTM:NG") tariff to allow the participation of behind-the-meter generation resources in its capacity markets. While NECHPI does not want to delay the resolution of this program to await the Commission's decision on a final BCAF, it is important to have the localized and temporal costs and benefits associated with DERs clarified and those associated with microgrids and hybrid systems specified and included in the final BCAF. A clear indication is the puzzling lack of discussion in the CBAF on values associated with the key REV and State clean-energy goals of resiliency and reliability. These are critically important values to CHP on a stand-alone basis as well as part of microgrids and district energy systems, and should be well-articulated and supported values in the CBAF.

- Entirely missing from the CBAF are values associated with thermal energy, a key value for CHP, both renewables- and gas-fired, as well as other distributed resources that provide thermal value such as renewables heating and cooling. For example, there is no recognition or discussion of CHP as part of district energy systems where electric, heating and cooling grids are integrated into one energy eco system. The unique set of both electricity and thermal benefits are not reflected in the Staff's list of costs and benefits, which are focused exclusively on the electric grid. NECHPI requests that the

Commission urge the Staff to include in the CBAF costs and benefits associated with heating and cooling and their integration with the electric grid.

The Incorporation of Benefits and Costs Associated with CHP and Thermal Energy into the Proposed BCAF

- **REV itself has been entirely focused on the electric grid, so it is not surprising that there is an absence of the benefits associated with thermal energy. However, NECHPI has pointed out in numerous of its other comments throughout this proceeding that there is considerable empirical evidence that the State will not achieve many of its clean-energy goals, most particularly projected renewable energy penetration levels and GHG emissions reductions, without incorporating explicitly the integration of electricity, gas, heating and cooling into the CBAF.** There is ample justification, data, case studies and other empirical analyses, most particularly in Europe and Japan, that support the importance of the convergence in thinking about clean-energy systems that bring together both heat/cooling and electricity. In fact, in many countries in Europe as an example, it is now considered a truism that renewables alone are unlikely to achieve the carbon reductions sought by governments. (This was discussed more fully in NECHPI comments on the Clean Energy Fund Information Supplement filed on August 14, 2015. Please also see supporting information in Appendix C.)

- <u>Appendix C presents case studies in Germany and the U.S. that demonstrate that CHP is key to the reduction in GHG emissions in geographies with high penetrations of renewables</u>. Recent analyses of Germany and California show massive increases in renewables over the last 10 years but the same level of GHG emissions and much higher electricity prices during the same time period. These "unintended consequences" are a direct result of the rapid scale-up of renewables without considering the balancing and firming requirements of the grid. There have been analyses that demonstrate that Solar PV and wind on their own will not be able to achieve a zero-emissions future since they cause indirect effects that produce higher levels of GHG emissions when central generators are forced to compensate for their variability and uncertainty. <u>NECHPI believes that the Commission has the opportunity to anticipate these unintended consequences resulting from the rapid scale-up of renewables and ensure that mechanisms are in place, starting with the CBAF, that support the inclusion of the benefits and costs associated with renewables integration for technologies such as CHP and energy storage.</u>

- <u>A technology-agnostic, fuel-neutral approach to REV objectives is based on the premise that standardized, fair, transparent, replicable and scalable methodologies, procedures, processes and associated documentation are utilized in order to level the playing field and ensure that the right technology, or combination of technologies, are selected and appropriately compensated for meeting certain grid and/or customer requirements and represent the least cost/best fit for the application/service in question.</u> The selection should not be based on pre-existing opinions about the relative benefits of various technologies but on engineering and economic-driven analysis, empirical data and a resource's ability to provide the required services while meeting State clean-energy goals and REV objectives. For example, <u>NECHPI maintains that the BCAF should provide the correct framework to avoid unintended disincentives and negative financial and operational consequences for CHP, most particularly natural gas-fired units, and to provide appropriate support of the GHG emissions-mitigation strategies that CHP provides.</u>

- <u>The profound and increasing inter-relationships between energy and the environment are raising concerns about their lack of integration. While NECHPI recognizes that the Commission has recently</u>

directed Staff to cooperate with the State Department of Environmental Conservation ("DEC") in the development of the proposed DEC emissions rules related to distributed generation, the lack of transparency on the deliberations and the inadequate analysis in NECHPI's estimation of environmental impacts of various distributed energy resources as articulated in the State's Final Generic Environmental Impact Statement, issued February 6, 2015, are causes for concern. NECHPI notes that the lack of alignment of an analysis of costs and benefits associated with environmental issues in the GEIS and the proposed CBAF, as well as the many missing elements in both approaches, put CHP at a grave disadvantage in the marketplace. Instead of a technology-agnostic, fuel-neutral approach, NECHPI notes a complete lack of discussion about output-based emissions standards, sophisticated fuel-displacement methodologies which account for both electricity and thermal energy and many other factors which level of the playing field.

- The CBAF should include values associated with both absolute emissions reduction targets and energy reductions based on carbon intensity. The proposed CBAF is focused entirely on absolute emissions reduction targets (that is, the total quantity of greenhouse gas emissions being emitted) compared to energy intensity reductions (namely, the amount of emissions to some unit of economic output). NECHPI argues that these are complementary targets, and both should be a part of the CBAF. In terms of absolute reductions, NECHPI believes that CHP is able to contribute to absolute reductions in emissions as long as all of the benefits and costs are accounted for. In terms of energy-intensity reductions, while New York State does support output-based emission standards, they have not been incorporated into the CBAF nor has it even been mentioned.

- In comparison to an "input-based" approach which provides no correlation between the amount of fuel used and the amount of electricity generated, an output-based approach (also known as efficiency-based or performance-based) rewards those generators, such as CHP, producing the same amount or more energy while emitting fewer pollutants. CHP produces two outputs – thermal and electric - and allows for the productive use of much of the waste heat from electricity production, which accounts for about two-thirds of the energy used to generate electricity. Only output-based measurements can capture the total efficiency provided from such a single source of fuel producing both electricity and thermal energy (heating and cooling).

- Not using output-based emissions standards in the CBAF puts CHP in a highly disadvantageous position since it is one of the key means to "level the playing field" and allow CHP to provide the multiple benefits it is able to provide to both the grid and loads while reducing significantly GHG emissions levels as well as toxic criteria pollutants. See Appendix E for a comparison of a 10 MW CHP plant to a 10 MW solar PV and a 10 MW wind plant. It graphically demonstrates CHP's ability to provide substantial levels of highly efficient electrical and thermal energy while greatly reducing GHG emissions levels per unit of production.

- Output-based regulations ("OBRs") are based on emission limits expressed in terms of electric output (lbs/MWh) for electric generators; thermal output (lbs/MMBtu) for steam boilers; or mechanical output (gms/bhp-hr) for reciprocating internal combustion engines. (The unit of measurement in which the additional output is credited will depend on if the CHP system is thermal-based or electricity-based. There are two common approaches to credit both CHP outputs in OBR: equivalence approach and avoided emissions approach. Without going into detail here, the two approaches can result in different calculated levels of efficiency and different output emissions rates based on the amount of total output considered. Texas and California use the equivalence approach while Massachusetts and Connecticut use the avoided emissions approach. The following compares the calculations based on the two approaches.[2] Whatever the approach taken, the following demonstrates that there are states actively incorporating thermal-based OBRs into their DER financial-support policies.

Thermal-Based OBR*	Equivalence Approach	Avoided Emissions Approach
CHP Electric Capacity, MW	1 MW	
CHP Useful Thermal Output , MMBtu/hr	15 MMBtu/hr	
CHP Electricity Output, MWh	1 MWh	
Boiler Emissions, lb/MMBtu $_{\text{fuel input}}$	0.1 lb/MMBtu $_{\text{fuel}}$	
Boiler Fuel Use, MMBtu/hr	23.2 MMBtu/hr	
Boiler Emissions, lb/hr	2.32 lb/hr	
Electricity Thermal Equivalence,MMBtu/kWh	10,000 Btu/kWh	N/A
Avoided Central Station Emissions, lb/MWh	N/A	0.8 lb/MWh
CHP Output-Based Emission, lb/MMBtu $_{\text{steam}}$	**0.093** lb/MMBtu$_{\text{steam}}$	**0.101** lb/MMBtu $_{\text{steam}}$

*The example is based on a 1 MW steam turbine generator that has measured emissions rate of 2.32 lb/hr (based on a fuel input emissions rate of 0.1 lb/MMBtu). In CHP configuration, the system provides 15 MMBtu/hr of process thermal energy (about 15,000 lb steam/hr) and 1 MWh of net electricity output.

- Under the proposed CBAF, CHP systems will not be accurately credited unless specific guidance is given which recognizes and accounts for a CHP system's added efficiency benefit, thus stifling investment in highly efficient, reliable and low-emitting power technologies. OBRs recognize and reward efficiency, which translates into reduced fuel consumption and multi-emission reductions (not just GHG emissions but also criteria pollutants) and relates cost to benefit as part of an emissions control strategy to allow additional compliance options. While there are two approaches for calculating output (thermal output equivalence analysis and displaced emissions), the EPA has developed best practice options for CHP in particular, and technologies are available for measuring and validating output of both electricity and thermal energy. While somewhat dated, the following is an EPA summary of current state practices for accounting for thermal output. This is meant to represent the range of possible policies states can adopt for incorporating the benefits of CHP[3]. The Commission should direct Staff to include an investigation of the various approaches to the inclusion of OBRs into the CBAF:

[2] *Credits for Combined Heat and Power (CHP) in Output-Based Environmental Regulations*, Neeharika Naik-Dhungel, Program Manager, US EPA CHP Partnership, IDEA 2012 Annual Conference, July 2, 2012
[3] Downloaded from the EPA website on September 7, 2015. http://epa.gov/chp/policies/output_fs.html

Table 2: State Output-Based Environmental Regulations

State	Conventional Emissions Limit	Small DG Rule	Allowance Trading	Allowance Set-Asides	Emissions Performance Standard (EPS)
Arkansas			X*		
California		X*			X
Connecticut		X*	X*	X*	
Delaware	X*				
Illinois			X*	X*	
Indiana			X	X	
Maine	X				
Massachusetts	X	X	X*	X	
Missouri			X*	X*	
New Hampshire	X				
New Jersey			X*	X*	
New York		X (proposed)			
Ohio			X*		
Oregon					X
Pennsylvania			X*		
Rhode Island	X*				
Texas		X*			
Washington					X
Wisconsin			X*		

* Includes recognition of CHP by accounting for thermal output.

- <u>The EPA is also developing a heat metering standard to support the comparable and accurate attribution of the energy, financial and environmental benefits generated from thermal energy sources and renewable heating and cooling technologies</u>. This is important on many levels given the increasing focus on heating and cooling, particularly renewables-based; state recognition of thermal energy sources in state RPSs and EERSs; an increasing focus on the thermal energy component of buildings (e.g., national green building standards); and the inclusion of thermal energy in financial models for third-party ownership and energy purchase contracts and agreements. [4]

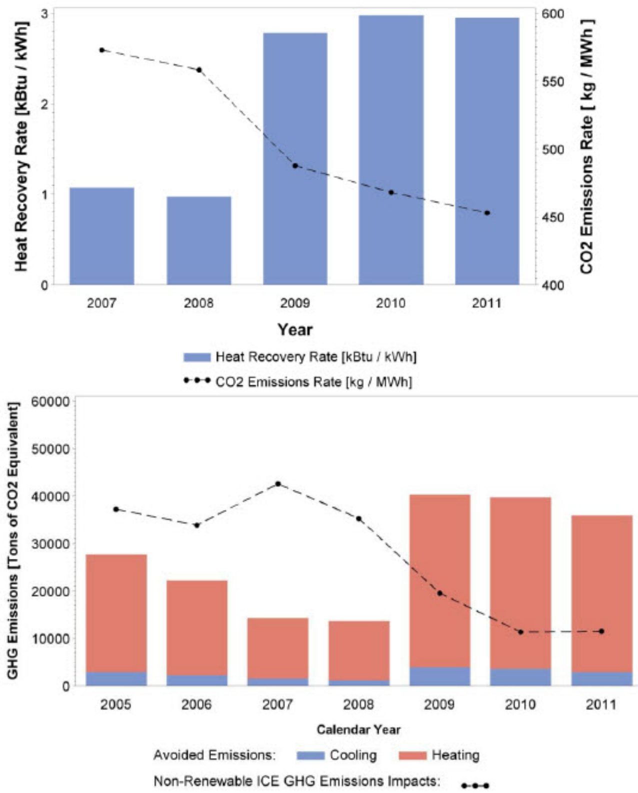
  <u>Massachusetts provides an excellent policy example</u> in its Alternative Portfolio Standard ("APS") and MassSave Efficiency Programs which include performance-based incentives for steam-generating CHP systems, with the State currently in process of implementing performance-based incentives for steam generated by renewable biofuels and waste heat recovery boilers. The APS CHP credits CHP attributes of efficiency and net source GHG emissions reduction per unit of useful energy generated. Qualified units generate one tradable credit for each MWH of net source-fuel energy saved as quantified based on metered fuel consumption, net kWh and net useful BTUs delivered to loads. Credits are sold by generators at market price to load serving entities to fulfill their APS obligations (% of retail kWh, which escalates by 0.25%/year from 3.75% in 2015 to 5.0% in 2020).

  The State is in process of expanding the APS to issue credits to qualified systems that generate useful thermal energy using sunlight, biomass, biogas, liquid biofuel or naturally occurring temperature differences in ground, air or water. The State has recommended a multiplier for non-emitting resources and will re-evaluate periodically based on market uptake. One alternative energy credit equals 1 MWh equal 3.412 MMBtu. The multipliers will be applied to 1 AEC divided by levelized

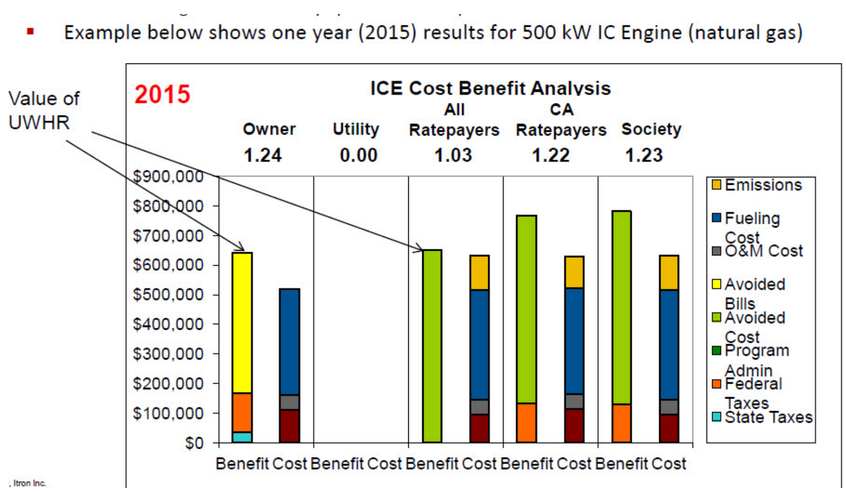
[4] *U.S. Heat Metering Standard: A Pathway to the Accurate Valuation of Thermal Energy,* U.S. EPA, James Critchfield, IDEA 104th Annual Campus Energy Conference, June 3, 2013

cost of energy of renewable thermal technologies. Solar DHW will have a multiplier of 5; solar combinations 2; and ground-source heat pumps 3.

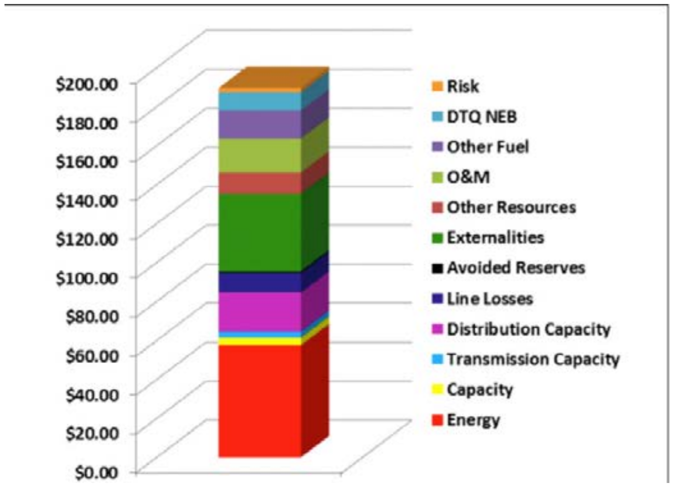
California's SGIP program is also an excellent example of using CHP to achieve net GHG emissions reductions. Useful waste heat recovery has been found to be a key to obtaining net GHG emission reductions and to provide healthy financial returns to the CHP project. The following shows the impacts of useful waste heat recovery ("UWHR") on GHG emission reductions. (Itron has been the primary evaluator of the program.)



The following is the Itron's cost-benefit analysis of the UWHR of natural gas-fired CHP IC engine.



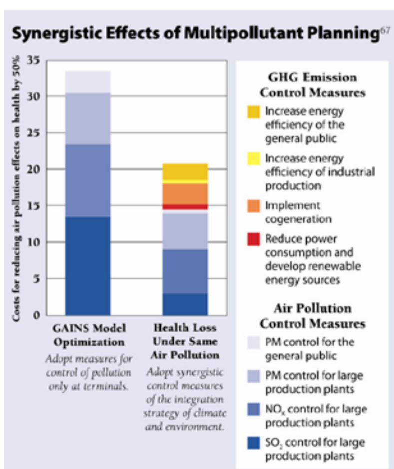
- NECHPI would also like to note that CHP reduces not only CO2 but emits toxic criteria pollutants at very low levels. Criteria pollutants are only mentioned in passing in the Staff White Paper. NECHPI recommends that the Staff more fully develop its approach to criteria pollutants and investigate integrated multi-pollutant planning for energy and air quality.[5] RAP has developed an approach to plan and regulate multi-pollutants on an integrated basis in order to lower costs as well as identify co-benefits. RAP argues that multi-pollutant measures (e.g., energy efficiency) offer extraordinary co-benefits:



US$ / MWh

(Source: RAP, 2012, Vermont Data)

RAP also notes that the multipollutant mitigation approach offers substantial economic benefits:



Synergistic Effects of a Multi-Pollutant Approach Offer Economic Benefits

Design Task: Reduce air pollution health impacts by 50%.

(Source: Based upon Bollen et al, 2009 cited in RAP 2012, Integrating Energy and Environmental Policy)

While apparently not currently active, RAP worked with the Northeast States for Coordinating Air Use Management ("NESCAUM") and the EPA between 2010 and 2013 to identify in New York State an integrated set of policies to jointly reduce air pollutants (including mercury) and GHGs. The proposed measures modeled for included: impacts on the energy sector, local economic effects, costs and benefits and reductions in ambient PM 2.5 and ozone levels. Maryland is working on a multi-pollutant framework to quantify the emission reductions of multiple pollutants

[5] *Integrated, Multi-Pollutant Planning for Energy and Air Quality (IMPEAQ)*, Regulatory Assistance Project, Christopher James and Kenneth Colburn, March 4, 2013

for a broad suite of DER measures, to estimate the public health benefits associated with improved ambient pollution levels, and to quantify the economic benefits and costs.

While it is NECHPI's understanding that this initiative is no longer active, it believes that it would be in the State's interest to evaluate the approach in the context of the CBAF. The unintended consequences of addressing pollutants individually include tradeoffs where some emissions may increase or where additional costs may be imposed on the energy sector. (e.g., increased penetration of electric vehicles can reduce hydrocarbon emissions but may increase NOx, SO2 and fine particle emissions). Environmental and energy regulation do have tradeoffs, but using multi-pollutant analysis can explicitly reveal the tradeoffs, allowing for constraints, costs and benefits to be evaluated and future policies prioritized.

- NECHPI has significant concerns about the final Generic Environmental Impact Statement ("GEIS") and its implications for CHP's role in REV and in the emerging 21st century energy ecosystem. Firstly, the GEIS employs a different set of methodologies for calculating DER values and environmental impacts than proposed in the CBAF. More importantly, the final GEIS is focused on a single measurement of peak-load reduction to establish environmental impact levels. At one point in the document, the GEIS states that "on average, across all potential scenarios, CHP systems result in no net reduction in emissions."[6] NECHPI strongly disagrees with the results, which can be amply supported about all of the empirical analyses and approaches discussed in the current comments. Thus, NECHPI strongly urges the Commission to direct Staff to include the range of benefits discussed in these comments in the proposed Cost Benefit Analysis Framework.

    - It should be noted, however, that in order to meet significant GHG emissions reduction goals, combinations of resources are needed to decarbonize both the local and bulk-power grid and provide peak-load reduction capabilities. For example, Princeton University already operates its own highly efficient microgrid utility system supplying power, district heating and district cooling through a combination of natural gas-fired CHP, heat-driven chillers, solar PV and thermal energy storage. This combination has enabled the university to cut its peak power demand on the regional power grid from 27 MW to only 2 MW. Princeton counts CHP as critical in achieving both peak-load and GHG emissions reductions..

- The Staff should also be directed to consider adopting a rigorous methodology for estimating generation fuel displacement by avoided use of grid electricity by the array of distributed energy resources. As an example, the Energy Assessments Division of the California Energy Commission ("CEC") released a staff paper in June 2015[7] as part of a stakeholder process to develop methods for calculating emissions reductions resulting from avoided generation for the preferred resources in California's loading order – energy efficiency, demand response, renewable generation and CHP. NECHPI believes that such a methodology should be incorporated into the proposed CBAF.

    - The study points out that currently there are many different methods used and that they vary substantially in approach and assumptions depending on the specific program or purpose for

[6] *Final Generic Environmental Impact State in Case 14-M-0101 – Reforming the Energy Vision and Case 14-M-0094 – Clean Energy Fund*, prepared by Industrial Economics, Incorporated and Optimal Energy, Incorporated for NYSERDA, February 6, 2015

[7] *Proposed Near-Term Method for Estimating Generation Fuel Displaced by Avoided Use of Grid Electricity*, Bryan Neff, Supply Analysis Office, Energy Assessments Division, California Energy Commission, June 2015, CEC-200-2015-002

which they were designed. The approach being adopted by the CEC is to use policy-neutral assumptions and methods to estimate emission reductions by the various programs that encourage preferred resources. NECHPI will not go over all of the assumptions behind the analyses but will provide a summary of key stakeholder comments to emphasize further model refinements. The following table summarizes the examples for avoided energy, displaced fuel equivalent, carbon content and carbon intensity for each of the distributed resources in the State's preferred-resource loading order. (It should be noted that the difference between the two renewable-generation scenarios illustrates the impact line losses have on the calculation.)

Table 2: Five–Year Displacement Totals and Average Carbon Intensity

Illustrative Example	Five-Year Total CO_2 Conversion (metric tonnes CO_2)	Five-Year Total Avoided Grid Energy (MWh)	Average Avoided Carbon Intensity (kg CO_2/MWh)
Renewable (export)	2,920	37,885	386
Combined Heat and Power	14,299	176,523	405
Renewable (onsite)	3,167	37,885	418
Energy Efficiency	737	8,765	420
Demand Response	149	1,227	605

Source: California Energy Commission, Supply Analysis Office, Energy Assessments Division.

- The following additional comments on the fuel-displacement proceedings are important to the CHP community because they highlight various missing important elements in the analysis and proposed methodology:

  - A comprehensive CHP evaluation must capture both the electric and thermal energy streams inherent to CHP resources and account for the total fuel efficiencies provided by them. The methodology should be modified to include quantifying both benefits and produce a comprehensive measure of total fuel savings and average carbon intensity provided by CHP resources.

  - For CHP, GHG emissions are the total generation emissions net of avoided natural gas boiler emissions.

  - Gas-fired CHP should be listed and analyzed separately from carbon-neutral forms of CHP (e.g., bottoming-cycle CHP or renewables-fueled CHP).

  - The California Cogeneration Council noted that geographic and temporal detail would improve the analysis. Various assumptions used about annual heat rates may be appropriate for baseload resources but may not be appropriate for load-following or peaking CHP resources that produce substantially more energy on-peak than off-peak when less efficient units are on the system margin.

  - Similarly, a statewide approach may not be accurate if an analysis is to apply to resources that are located within a congested region of CAISO.

  - Finally, the analysis may not be appropriate for evaluating large blocks of generation (e.g., all CHP, not just a specific CHP project).

  - Thus, the CBAF needs to capture the electricity and thermal costs and benefits related to CHP, including avoided carbon intensity. Many CHP assumptions are location-specific, dependent on the amount of exports, operational strategy, and flexibility capabilities among others. In general, much more granularity will be needed for all DERs, including CHP. Factors to include will be modeling corresponding load shapes of resource types, peak/off-peak hours of operation and seasonal variation of heat rates.

- The California proceeding represents an initial attempt to provide a consistent, standardized approach and framework for estimating electric-grid fuel displacement by various distributed-energy resources. The process is on-going, and NECHPI expects to see further iterations of the methodology and associated analyses. NECHPI recommends that New York State through the CBAF process investigate a reasonable and consistent fuel-displacement accounting method that can be used for renewable generation, CHP, demand response, energy efficiency and other DERs such as energy storage and EVs in order to ensure that both the costs and benefits of various technologies are being properly analyzed and valued.

- Thus, NECHPI offers to work closely with Staff to discuss the potential impact of EPA's recently issued Clean Power Plan at both the retail and wholesale levels, the impact of distributed energy resources, including CHP, on urban communities and the proposed rule's interaction with other environmental regulations. NECHPI understands the concerns about the potential for local emissions resulting from gas-fired CHP; however, it believes that, with a balanced analysis of the costs and benefits in the context of the alternatives, an agreed-upon pathway can be found to provide substantial benefits to the State, including significant reductions in GHG and criteria-pollutant emissions. ACEEE has written extensively about CHP's role in the Clean Power Plan and has provided a template for including CHP in state compliance plans. While not directly related to the proposed CBAF being discussed in the current comments, the template provides a framework for analyzing specific costs and benefits not included in the proposed CBAF. [8]

The Role of Natural Gas in the State's Clean-Energy Future and Its Integration into REV Initiatives

- Putting a price on carbon will effect some positive change and is an important component to a total solution but, if relied on too heavily, the price needed to meet the State's articulated clean-energy goals may be so high as to make the policy unfeasible. NECHPI believes that there are other "low-hanging-fruit" approaches that will delivery effective, much lower-cost GHG emissions and criteria-pollutant emissions savings which should be considered first or at least alongside of carbon pricing.[9] The power system is complex, and NECHPI believes that what may seem sensible from one perspective (e.g., a focus on large-scale renewables scale-up) may in fact have unintended negative consequences, reducing the State's ability to meet its long-term clean-energy goals.

- The emergence of the importance of natural gas nationally, regionally and on a statewide basis is further driving the need to integrate more fully energy and environmental policy, rules and regulations. The unprecedented, and in many ways unexpected, rise and vast potential of unconventional, low-

[8] *Navigating the Clean Power Plan: A Template for Including Combined Heat and Power in State Compliance Plans*, American Council for an Energy-Efficiency Economy, Meegan Kelly, June 2, 2015
[9] *Clean First: Aligning Power Sector Regulation with Environmental and Climate Goals*, RAP, September 2010

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cost natural gas is the latest development highlighting the deeply interconnected nature of energy and environmental issues. The substitution of coal-fired generation with gas-fired generation is spreading and is delivering environmental benefits associated with NOx emissions rates that are a fraction of those of coal, along with negligible SO2, particulate and mercury emissions. Although natural gas-fired central generation plants still produces about half as much CO2 per kWh as coal, it is still a substantial source of carbon. It also makes renewable generation less competitive by comparison in the current marketplace. A Regulatory Assistance Project ("RAP") report states in conclusion: "Ensuring that the current natural gas boom results in a net reduction in harmful emissions, safe and optimal use of water resources, and the use of natural gas-fired generation as a transition to a decarbonized power sector (instead of an obstacle to it) will require clean, science-based environmental policy and regulatory integration and oversight as new natural gas supplies come online globally."[10]

- NYISO[11] emphasizes the importance of natural gas to the future of New York State's bulk power system. In NECHPI's estimation, natural gas is a friend of DERs and renewables, and needs to be fully integrated into distribution planning. It is, and will remain for the foreseeable future, a critical part of New York State's energy future, and these proceedings should not ignore this fact of life. Wishing it away or pretending the trends do not exist does not help find the long-term solution for New York's clean-energy future. NYISO's recently released 2015 Power Trends Report, which evaluates the long-term planning requirements for the State's electric power system, notes not only the continued use of natural gas (natural gas only as well as dual-use fuels, gas and oil) for electricity generation but also plans to ramp it up significantly in the coming years. Aside from a welcome decrease in energy costs since 2009, the report also highlights increased emissions reductions since it started using more natural gas for electricity generation: from 2000 through 2014, New York power plant emission rates dropped by double digits; SO2 emissions rates declined 94%; NOX emissions rates declined 78%; and CO2 emission rates declined 39%. (See Appendix F for more detail on NYISO power-plant statistics.

- Another important, but little discussed, issue surrounding low natural gas prices is its impact on cost-effectiveness screening practices of both gas and energy efficiency programs. Lawrence Berkeley National Laboratory in several policy briefs[12] notes that abundant, affordable natural gas is placing gas-efficiency programs at a crossroads. Some program administrators are finding that conventional analyses which only consider a narrow set of energy savings-related efficiency program benefits are now resulting in many gas-efficiency programs failing to pass the criteria used to screen programs for cost-effectiveness depending on program design, location, fuel mix and other factors. The decrease in natural gas prices over the last several years, by reducing avoided cost forecasts, makes it more difficult for gas-efficiency measures and programs to pass cost-effectiveness tests.

    - LBNL found in its analyses that combination-fuel and gas-only residential programs have difficult passing the most common TRC cost-effectiveness test without shifting either to portfolio-level screening, using a discount rate substantially below a utility WACC or accounting for a range of non-energy benefits. The findings also underscore the increasing mutual dependency that electric

[10] *Integrating Energy and Environmental Policy,* Regulatory Assistance Project, January 2013
[11] *NYISO 2015 Power Trends Report*
[12] *Implications of Cost Effectiveness Screening Practices in Low natural Gas Price Environment*, LBNL, Environmental Energy Technologies Division, authors Ian Hoffman, Merrian Borgeson and Mark Zimring, April 16, 2013 and *Assessing Natural Gas Energy Efficiency Programs in a Low-Price Environment*, LBNL, Environmental Energy Technologies Division, authors Ian Hoffman, Mark Zimring and Steven R. Schiller, April 30, 2013

and gas program administrators may have if and when new energy efficiency standards for end uses of both fuels coincide with low gas prices. “Operating separately gas- and electric-only program administrators may, under current market conditions, leave substantial opportunities for savings of the other fuel untapped and, in practical terms, less accessible for meeting energy savings goals and other related state policy objectives.” In addition, if additional benefits besides energy savings are included in a cost-effectiveness screening test (e.g., hedge value, downward price pressure on gas from reduced demand, easing gas transmission capacity constraints, enhancement of electricity reliability, environmental benefits, economic development and avoided economic and programmatic costs of ending/suspending programs), many gas efficiency programs become cost-effective, particularly when they are analyzed on a portfolio basis.

- Finally, LBNL notes that delivering gas and electric efficiency programs together has the benefit of avoiding the loss of technically and economically viable efficiency potential. Energy efficiency technical potential comes from individual end uses and the interaction of those measures with one another and the facility itself in which they are implemented. Ignoring the benefits of energy savings from “other fuels” may lead regulators and administrators of gas efficiency programs to undervalue investment in packages of measures that deliver savings across fuels.

- One of the LBNL authors, Ian Hoffman, noted in a private email communication dated September 4, 2015 that while direct-use natural gas (and efficiency programs aimed at it) are not credited under the Clean Power Plan, he believes that these programs have a complementary role to play not only in reducing methane emissions but also in supporting compliance on the electricity side. Ultimately, regions that are reliant on gas-fired generation (such as New York and New England) and subject to supply-side price premiums are likely to increase that reliance and perhaps become more vulnerable to wholesale prices under a CPP regime as a result of fuel switching and integration of renewables at higher penetrations. The reduction in direct use of natural gas helps alleviate gas supply/system constraints, lowers wholesale prices and *can* make more gas available at lower prices to the power sector, thus enabling a CPP compliance path, possibly at lower cost than other sources of abatement. The differential in abatement cost therefore might be counted as a benefit in gas-efficiency programs. While speculative at this point, NECHPI points this out as a possible emerging benefit of gas-efficiency programs.

DER Cost-Effectiveness Screening Tests

General

- In NECHPI’s estimation, the proposed CBAF is a basically using a traditional approach based on variations of the California Standard Practice Manual for Energy Efficiency and has attempted to graft on modifications to account for “externalities” and to apply cost-effectiveness screening tests originally developed for energy efficiency to all DERs. California itself has a number of proceedings in process which are re-evaluating the cost-effectiveness screens outlined in the California Standard Practice Manual and whether and how they are applicable to distributed energy resources other than energy efficiency (e.g., demand response, distributed generation, and distributed storage). These proceedings are noteworthy for their depth of analysis of all of the critical issues associated with the development and implementation of a CBAF and its relationship to measure, program and portfolio cost-effectiveness tests.

- There is simply too much data and analysis to summarize key points concerning the application of cost-effectiveness screening tests and how the field has changed over a number of decades. Most analyses discuss the tradeoffs/pluses and minuses between various tests and how most states have chosen a particular test and then modified it to support its own policy goals. In essence, no one state is the same in how it uses and applies cost-effectiveness tests. Suffice it to say, the discussion in the proposed CBAF, and the associated comments, do not address many of the issues put forth in the literature on the topic. NECHPI is concerned because it feels as if the State is trying to re-create the wheel and attempt to resolve the numerous issues associated with cost-effectiveness screening tests, many of which have already been addressed or treated in some detail in other proceedings in other states, most particularly in California, which originated the tests in the first place.

- In addition, NECHPI had hoped that the State would view this is an opportunity to learn from others' experiences, including mistakes, and leapfrog efforts to adopt innovative approaches to the development and implementation of a CBAF and the types of cost-effectiveness screening techniques used not only for energy efficiency but for other distributed energy resources. California is already engaged in proceedings to re-evaluate cost-effectiveness measures for DR, DG in addition to EE and the types of cost-benefit analyses required to identify and support cost-effective resources.

- The current California DR proceeding in particular is interesting[13] in that it notes that methods used to measure DR costs and benefits which need to be updated to capture emerging benefits because of the increased use of automated technology as well as a variety of other developments. The rulemaking also noted that the protocols previously in place needed to be updated to address the broad variety of DR programs, both existing and new; identify all relevant inputs that are important for determining the cost-effectiveness of DR; establish methods for determining the value of those inputs; and determine a useable overall framework and methods for evaluating the cost-effectiveness of each of the different types of DR activities. In addition, the DR protocols established in 2010 were found to have deficiencies based on problems encountered in the first utility filings for the DR 2012 – 2014 budget applications. The problems found were:

    - Inconsistency among the IOUs' calculation of the five adjustment factors (availability, notification time, value of flexibility of triggers, distribution, and energy price, with location being added as a new adjustment factor in these new proceedings);
    - Inconsistency among the IOUs' allocation of support program budgets such as ME&O, EM&V and IT to each DR program;
    - IOUs' lack of qualitative analysis of the optional costs and benefits; and
    - Lack of definition of the DR portfolio and inconsistency among the IOUs' perceptions of what should be included in the DR portfolio.

- The California DR cost-effectiveness proceeding is too complex and detailed to discuss in detail here. However, it is important for highlighting the problems which emerged from its first DR cost-effectiveness protocols, essentially all of which were related to inconsistencies amongst utilities in program measurement and implementation. New York needs to learn from this experience to ensure that similar problems do not occur not only in utility DR programs but all DER-related programs and initiatives.

[13] *Before the Public Utilities Commission of the State of California, Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operations Requirements, Administrative Law Judge's Ruling Requesting Comments Regarding the Cost-Effectiveness Protocols and the Valuation Working Group Report filed June 19, 2015*, Rulemaking 13-09-011 filed September 19, 2013

Approaches to the Selection of Screening Tests: Societal versus Other Approaches

- It should be kept in mind that the cost-effectiveness screening tests were developed for energy utility energy-efficiency programs and are being applied to other resources only in the relatively recent past. It is an important point, one that bears repeating in this context.

- A report[14] by the Regulatory Assistance Project ("RAP") provides significant detail on the different levels of screening and the applicability of various tests at different levels. Its primary recommendations include using the Societal Cost Test or TRC test at the program level; analyzing energy efficiency resources at the measure level in order to provide program administrators with the greatest level of detail regarding their costs and benefits but that the screening is best performed at the program level in order to reduce the risk of screening out measures that provide program-level benefits; considering potential bill impacts and customer equity concerns with either the Societal Cost Test or the TRC Test by applying the PAC test to the entire portfolio of efficiency programs to ensure that the entire package of programs will result in a net reduction in revenue requirements and a net reduction in costs to utility customers. In this case, the Societal Cost Test or TRC Test would be the primary test for screening each energy efficiency program, with the PAC test the secondary one applied to the portfolio of programs. This combined screening approach should be simple to apply.

	Utility Test	TRC Test	Societal Cost Test
Energy Efficiency Program Benefits:			
Avoided Energy Costs	Yes	Yes	Yes
Avoided Capacity Costs	Yes	Yes	Yes
Avoided Transmission and Distribution Costs	Yes	Yes	Yes
Wholesale Market Price Suppression Effects	Yes	Yes	Yes
Avoided Cost of Environmental Compliance	Yes	Yes	Yes
Non-Energy Benefits (utility perspective)	Yes	Yes	Yes
Non-Energy Benefits (participant perspective)	---	Yes	Yes
Non-Energy Benefits (societal perspective)	---	---	Yes
Energy Efficiency Program Costs:			
Program Administrator Costs	Yes	Yes	Yes
EE Measure Cost: Program Financial Incentive	Yes	Yes	Yes
EE Measure Cost: Participant Contribution	---	Yes	Yes

- In Synapse Energy Economics' analysis of cost-effective energy efficiency screening[15], the authors recommend that, ideally, the Societal Cost Test, the TRC Test as well as the PAC Test should all be considered when assessing energy efficiency cost effectiveness. However, it still begs the question of which test results should be used to determine the programs to implement and that, in practice, it is more common and straightforward to use a single, primary test to answer the question. The recommendation in this case is to use a primary test at the program level and a secondary test applied, at a minimum, at the portfolio level. This approach offers the benefits of both breadth and simplicity.

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[14] *Energy Efficiency Cost-Effectiveness Screening: How to Properly Account for 'Other Program Impacts' and Environmental Compliance Costs,* Synapse Energy Economics, Inc. for Regulatory Assistance Project, Tim Woolf, William Steinhurst, Erin Malone and Kenji Takahashi, November 2012

[15] *ibid*

- The question of whether to use a societal test requires the weighing of risks of possibly over-estimating the benefits of a program and thereby placing an inappropriate financial burden on ratepayers against the risk of undervaluing those benefits and not funding programs sufficiently to capture benefits that current and future ratepayers will enjoy. Because a societal test is essentially a TRC test with additional benefits (i.e., avoided externalities) included and a lower discount rate, many programs which would not be cost-effective based on the TRC test would be cost-effective based on a societal test. It raises many questions, too numerous to list here, but if the Commission approves a program which is cost-effective for society as a whole but not for ratepayers, can it avoid placing an unfair burden on ratepayers by requiring that program costs be shared? If it rejects the programs, what impact does that have on the larger society, including future generations?

- Nowhere is the risk more apparent than when considering the value of reducing greenhouse-gas emissions. Should the value be based on the actual costs of reducing GHG emissions? Or should it be based on the current costs of economic damages from events that are likely to have been caused by climate change? Or should it be based on the potential cost of damage imposed on future generations? Is it possible to estimate those future values with any certainty?

- Another important issue about a societal test is whether it should be used as a primary cost-effectiveness test, which is used to determine program or portfolio approval, or a secondary test, which provides additional information which could be used to modify program or portfolio design or indicate that a program should be only partially funded by ratepayers. It may be that, in order for a regulatory agency to fulfill its primary mandate to prove cost-effective energy services to ratepayers at reasonable costs while maintaining reliability, safety and resiliency, the societal test might be more appropriately a secondary test used to determine the net benefits of various policies to both ratepayers and the larger society so as to determine how the costs should be shared by various stakeholders, such as ratepayers, state and federal taxpayers, utilities, other businesses and private sector investors.

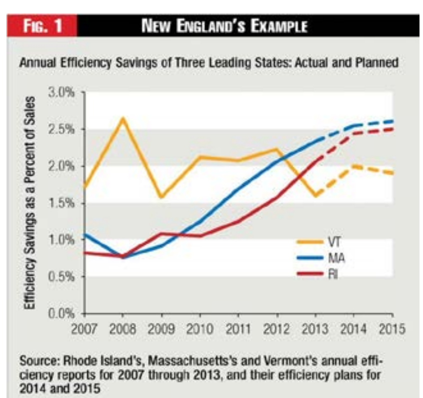
- RAP has also done significant work in particular on recognizing the full value of energy efficiency.[16] It discusses the :layer cake" of benefits from electric energy efficiency:
  - Utility system benefits
    - Power supply
    - T&D capacity
    - Environmental
    - Losses and reserves
    - Risk
    - Credit and collection
  - Participant benefits
    - Other fuels
    - Water, sewer
    - O&M costs
    - Health impacts
    - Employee productivity
    - Comfort
  - Societal benefits
    - Air quality

[16] *Recognizing the Full Value of Energy Efficiency: What's Under the Feel-Good Frosting of the World's Most Valuable Layer Cake of Benefits*, Regulatory Assistance Project, Jim Lazar and Ken Colburn, October 9, 2013

- Water
- Solid waste
- Energy security
- Economic Development
- Health impacts

- RAP's analysis observes that many regulators exclude or undervalue T&D benefits, undervalue line losses and reserves, exclude or undervalue risk benefits, and undervalue environmental costs. As an example, line losses and reserves can be substantially undervalued. RAP estimates that marginal losses can be 1.5x average losses, and on-peak marginal losses can be 3x average losses.

- In a recent article, the authors, who have been active in the REV proceedings, describe two of the most important barriers to "unleashing" the full value of energy efficiency programs: outdated screening practices and rate impact fears.[17] While the analysis is outdated in terms of the Clean Power Plan, it does make some cogent observations on energy efficiency programs in the U.S. and the best practices adopted in various states and their clearly superior performances. EPA identified 12 leading states that have achieved annual incremental savings rates of at least 1.5% of retail electricity sales, and EPA believes that these states provide evidence of an achievable goal for all states. The following chart is particularly notable from NECHPI's perspective given the historical performance of New York utilities' actual performance and their projected performances in recently submitted Energy Efficiency Implementation Plans:

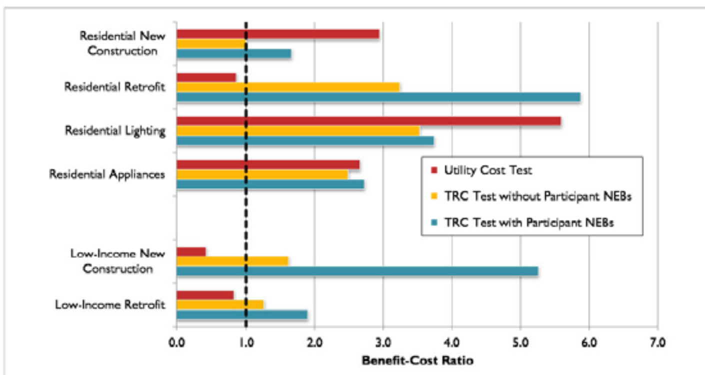


[17] *Unleashing Energy Efficiency: The Best Way to Comply with EPA's Clean Power Plan*, Public Utilities Fortnightly, Tim Woolf, Erin Malone, Chris Neme, and Robin LeBaron, October 2014

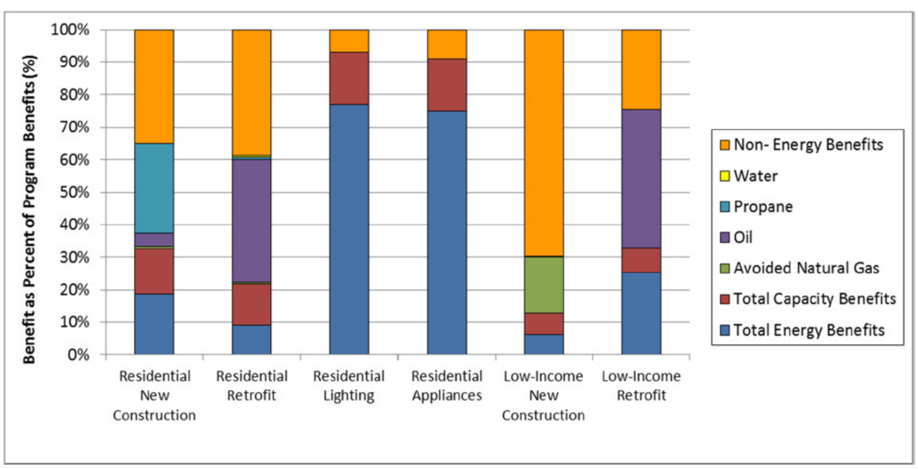
- NECHPI provides the following tables and graphs to represent the sheer complexity of the issues surrounding program cost-effectiveness screening tests[18], and these analyses are entirely focused on energy efficiency resources and have not been developed and implemented for other distributed energy resources.

- As is clear from the below tables and graphs, Massachusetts, whose utilities have had one of the best, if not the best, records in energy-efficiency programs in the country, shows substantially different cost-effectiveness results based on the type of test and the types of benefits accounts for. The graphs and tables for Northeastern states shows the contribution of different values to the cost-effectiveness of various measures and the variation amongst states based on the test employed. This discussion simply emphasizes the criticality of standardization, transparency and systematic application of valuing benefits and costs.

Actual Results – MA Program Administrator



Actual Results – MA Program Administrator



Energy Efficiency Screening Coalition – NARUC Presentation – 11/18/2013

Slide 32

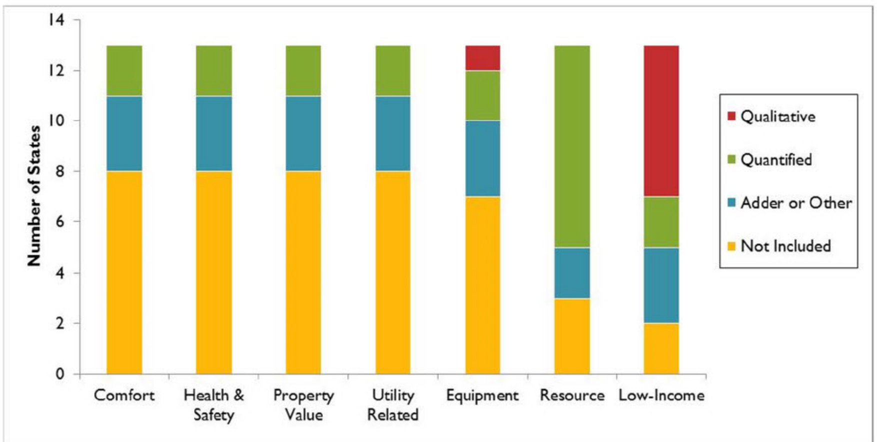
The following compares various energy-efficiency measures by Northeast state and type of screening test employed and whether values were quantified, qualitative or represented by proxies through "adders." As is apparent there are widely divergent paths taken state to state.

[18] *The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening*, Tim Woolf, the National Efficiency Screening Project, ACEEE Summer Study – Afternoon Discussion Session, August 21, 2014

Primary Test	UCT	Total Resource Cost Test					Societal Cost Test	
State	CT	MA	RI	NY	NH	DE	VT	DC
Low-Income	Qualitative	Quantified	Quantified	Qualitative	Qualitative		Add. 15% Adder	10% Adder
Equipment		Quantified	Quantified	Qualitative			O&M Quantified	O&M Quantified
Comfort		Quantified	Quantified				15% Adder	10% Adder
Health & Safety		Quantified	Quantified				15% Adder	10% Adder
Property Value		Quantified	Quantified				15% Adder	10% Adder
Utility Related		Quantified	Quantified				15% Adder	10% Adder

Quantified	Explicit $/participant, $/measure, $/kWh savings value per non-energy benefit
Adder	A percentage of quantified benefits
Qualitative	Most often used for Low Income programs The state allows for non-cost effective programs

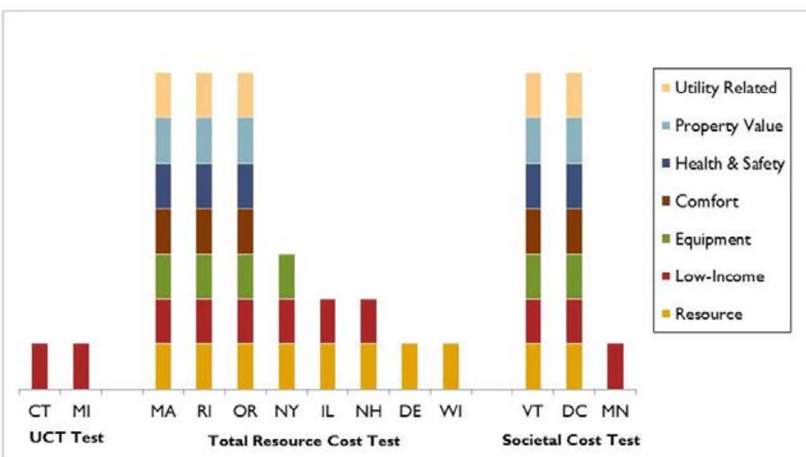
Based on surveys of 13 Northeast, Mid-Atlantic and Midwest States



Tim Woolf - National Efficiency Screening Project

Slide 30

Based on surveys of 13 Northeast, Mid-Atlantic and Midwest States



Tim Woolf - National Efficiency Screening Project

Slide 29

- <u>While the gap between leading and lagging states (New York for one) shows a vast opportunity for savings, the question is why New York has performed so poorly and what can be done to change the dynamics. Many argue that there needs to be a better framework for evaluating, screening and</u>

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selecting energy efficiency projects. The National Efficiency Screening Project ("NESP") developed the **Resource Value Framework** to address the deficiencies in existing cost-effectiveness screening processes.

- In order to meet the Commission's clearly articulated REV goals – provide low-cost electricity services, empower customers, animate the markets for distributed energy resources, improve system efficiency and resource diversity, ensure reliability and resiliency, and reduce greenhouse gas emissions – all components of a CBAF must be designed in a way to incorporate those goals, including the choice of screening test, the choice of discount rate, and the accounting for all relevant costs and benefits, including those associated with policy goals. **NECHPI believes that, instead of continuing to try to "tweak" existing standard cost-effectiveness tests, Staff should be developing an approach based on the Resource Value Framework based on the following principles: screening should identify those resources that are in the public interest; screening should account for energy policy goals of a state; screening practices should ensure that tests are applied symmetrically to both costs and benefits; hard-to-quantify impacts should not be ignored; and screening practices and assumptions must be transparent.**

- Synapse Energy Economics, the developer of the RVF, provides the following state-by-state comparisons of current energy-efficiency cost-effectiveness screening policies in place currently.

Public Policy	CA	CO	DE	IL	ME	MA	MI	NV	NM	NY	NC	RI	VT	VA	WA
All Available Energy Efficiency	✓				✓	✓			✓			✓	✓		✓
Utility System Policies:															
System Reliability*	✓		✓	✓				✓	✓	✓	✓	✓	✓	✓	
Affordability / Least Cost*	✓		✓	✓			✓		✓		✓	✓	✓	✓	
Resource Adequacy	✓		✓	✓			✓		✓	✓	✓	✓	✓	✓	
Resource Diversity*	✓	✓	✓	✓			✓	✓			✓	✓		✓	
Energy Security / Reduce Imported Fuels*	✓						✓		✓				✓		✓
Fair Utility Regulation				✓							✓				
Efficient Use of Resources / System Efficiency*			✓	✓				✓			✓	✓	✓	✓	
Economic Use of Resources*				✓				✓		✓	✓				
Consumer/Societal Policies:															
Public Interest (1)	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓		✓	
Reasonable Rates	✓	✓	✓	✓			✓		✓		✓				✓
Reduce the Burden on Low-Income Customers*									✓			✓		✓	
Equity				✓							✓	✓			
Economic Development*	✓	✓	✓					✓		✓		✓	✓	✓	✓
Meet Long-Term Needs		✓	✓	✓						✓	✓				
Encourage Private Investment							✓								
Environmental Policies:															
Environmental Quality (2)*	✓	✓	✓	✓			✓	✓	✓	✓		✓	✓	✓	✓
** An asterisk indicates a policy goal that efficiency helps to achieve.*															

Source: Synapse. Preliminary, high-level summary to illustrate the types of policies in used in some states. Not meant to be exhaustive.

- Synapse has stated that the RVF has been designed to be applicable for evaluating the costs and benefits of other demand-side and supply-side resources besides energy efficiency, although specific application to other resources will need to be developed and specified. See Appendix G for the RVF's cost-effectiveness screening templates, including a multi-attribute decision analysis ("MADA"), which provides a weighting of the factors used in the screening template.

- Synapse recommends that the societal cost test be used as the primary screen test; the utility cost test (also known as the program administrator cost or PAC test) should be used for the purpose of understanding bill impacts; and that the Rate Impact Measure (RIM) should not be used at all because it does not provide meaningful information about the magnitude of rate impacts or customer equity, among many other reasons. It recommends that other rate-impact approaches should be used in combination with cost-effectiveness screens to assess rate and bill impacts, equity impacts and participants. Taken together, these three factors indicate the extent to which customers will benefit from distributed energy resources.

- Synapse further elucidates how to account for the impacts through: 1) direct monetization wherever possible; 2) proxies (e.g., multiplier of avoided costs, multiplier on electricity saved, etc.); 3) alternative screening benchmarks (a pre-determined benefit-cost ratio benchmark of less than 1.0 to reflect benefits not accounted for with monetization or proxies.); and 4) regulatory judgment (which allows regulators to make cost-effectiveness determinations considering specific DER being analyzed and both the monetized and non-monetized impacts). Synapse further recommends the addition of multi-attribute decision analysis ("MADA"), a systematic process for weighting and scoring both monetized and non-monetized criteria in order to rank several options across all criteria. See Appendix G for sample CBA and MADA worksheets.

The Discount Rate Used in Cost-Effectiveness Screening Tests

- The discount rate is a complex issue, and much has been written on the subject not just recently but over decades. Risk benefits need to be considered in choosing a discount rate. If risks are addressed and incorporated into the analysis through other means, then the impact of the choice of discount rates should be moderated. However, in NECHPI's estimation, the proposed CBAF does not incorporate the level and variety of risks associated with DERs going into the future, nor does it incorporate the costs associated with risk-mitigation strategies.

- In addition, different stakeholders in the DER value chain – utilities, private investors, participants and society at large - have different return expectations and time preferences for investments. NECHPI has a major concern that REV has articulated repeatedly that the State must attractive substantial levels of private capital to be successful in achieving both REV and State clean-energy goals. In the "old" utility world of grid investments, this was simply not an issue. It goes without saying that the private sector has different views on return-on-investment and time-preference requirements. Thus, if the longer-term risks are not incorporated into the CBAF, then the application of a societal discount rate, whether it is 2%, 3%, or 5%, will greatly inflate the values of DERs since a low discount rate has such a major impact on cost-effectiveness.

DERs and Their Impact on Electricity Rates

- Another key issue is the effects of DERs on electricity rates. DERs, in particular energy efficiency, can affect electric rates in different ways: 1) upward because of the need to recover costs of the program or lost revenues from reduced sales or 2) downward because of costs avoided for generation, transmission or distribution and as energy costs fall at the margin, pushing rates down. The Fortnightly article[19] mentioned above recommends that a more thoughtful approach to DER rate impacts is necessary and requires the recognition that the central issue is about customer equity. The paper suggests the kinds of information necessary for Commissions to collect to in order to properly evaluate and balance the tradeoffs between the many benefits of energy efficiency, especially reduced bills, and customer equity concerns raised by rate impacts.

[19] *Unleashing Energy Efficiency: The Best Way to Comply with EPA's Clean Power Plan*, Public Utilities Fortnightly, Tim Woolf, Erin Malone, Chris Neme, and Robin LeBaron, October 2014

Measure, Program and Portfolio Cost-Effectiveness Screening

- NECHPI notes that there appears to be some confusion in a number of active-party comments on the definition of "portfolio" for use in cost-effectiveness tests. Essentially, a distinction is made in energy efficiency screening, for example, between a measure, a program, and a portfolio of programs. These are different ways to group energy-efficiency initiatives to apply cost-benefit analyses in order to establish cost-effectiveness. In general, it is recommended that a portfolio approach be taken to establish cost-effectiveness.

- NECHI places the following caveats on a cost-effectiveness screening approach that does not include project analysis for the following reasons:

    - REV is ultimately focused on locational and temporal values for all DERs, and cost-benefits are likely to vary significantly from circuit to circuit through the distribution, transmission and bulk-power systems. Thus, in NECHPI's estimation, there needs to be great care taken in not deeming projects cost-effective and then compensating them based on that assessment when, in fact, based on location, they are not cost-effective;

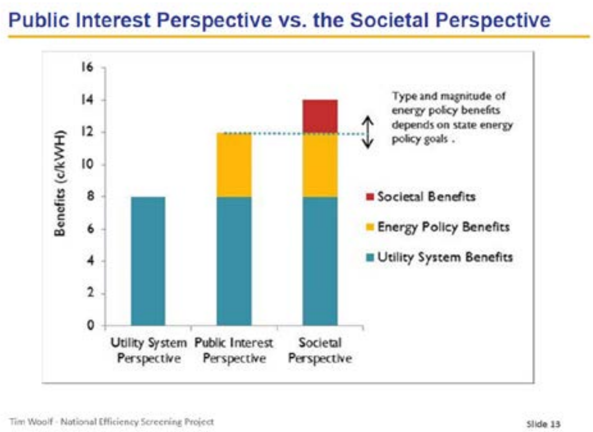
    - There is a difference between the meaning of portfolio when it is about a group of different programs for the same technology as compared to a "portfolio of assets" which can be a combination of a variety of distributed technologies with different performance characteristics, lifecycles, and so on. Valuing such a portfolio is different from the former meaning; and

    - When the word portfolio is used in the financial world, e.g., particularly in the context of securitization, it generally is referring to a group of assets that have the same performance profiles, can be evaluated similarly in terms of risks, returns on investments, tenors, and so on and be grouped together to achieve financial goals. These three definitions of portfolios need to be clearly differentiated and specified.

Additional Issues of Concern to NECHPI

- While the RVF framework utilities six principles for screening energy efficiency resources, **NECHPI is particularly focused on two of the principles: the distinction between societal and public benefits and the requirement that there be symmetry in costs and benefits.**

    - In determining whether a particular resource is in the public interest, screening practices should account for all state energy policy goals. However, the public interest perspective is not the same as the societal perspective. The societal perspective includes all relevant impacts to society at large, whereas the public interest perspective includes only those impacts within the bounds of regulators' scope or authority but greater than those entirely under the purview of the utility. Some societal impacts might fall outside of these bounds. This issue needs to be discussed amongst stakeholders if REV's CBAF should adopt a public-interest or a societal perspective.



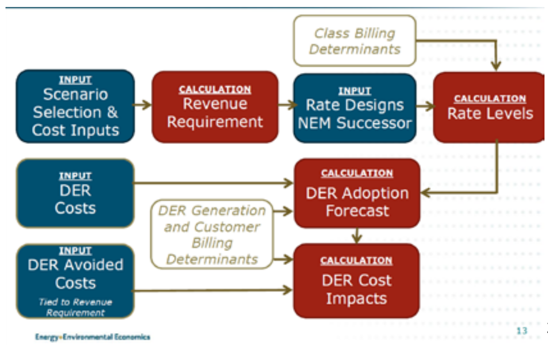
- Screening practices should also ensure that tests are applied symmetrically. That means that all relevant costs and relevant benefits are fully accounted for and included in the screening analysis. If a state chooses to include participant costs in its screening test, it must also include participant benefits, including non-energy benefits; otherwise, the test will be skewed against energy efficiency resources. If a societal cost test is used, the screening criteria must account for all benefits and costs from a utility perspective, participant perspective and societal perspective to the greatest extent possible. When using a TRC test, it is important to account for the utility perspective and the other program impacts ("OPIs") to the greatest extent possible.

- While NECHPI agrees that, in theory, a societal screening test should be applied as the primary screening test to incorporate the widest range of costs and benefits as possible, it is concerned that a host of benefits that CHP provides to the energy system are either missing or ignored. Some of these are related to the lack of incorporation of metrics associated with thermal energy and associated benefits both locally and system-wide as well as of the need to use more sophisticated output-based emissions standards and methodologies which serve to emphasize the importance of CHP in the energy mix to reduce levels of GHG and criteria pollutant emissions significantly. NECHPI urges the Commission to request that the CBAF include the full set of benefit and cost factors associated with CHP, both gas-fired and fueled by renewables), which would form the basis for the cost-effectiveness screening of all DERs, including CHP and other renewable heating and cooling technologies.

- NECHPI also recommends that the Commission provide guidance on different levels of required screening (by measure or technology, program and portfolio) and by type of test (ideally, in sequence based on what level of screening is being undertaken). The Commission should also require the use of scenario analyses based on alternative assumptions to get the most complete view of the cost-effectiveness of DER-specific projects, programs and portfolios. This will be particularly important given that so many programs will be new and may represent challenges in developing cost-effectiveness screening tests focused on a particular technology.

- The following brief discussion is simply to point out that these screening approaches discussed above are not in conflict with the implementation of EPRI's Integrated Grid BCAF. Rather, EPRI's approach is foundational and provides inputs to these and a variety of other cost-effectiveness screening tests, which help inform various stakeholder perspectives. The following public tool under development in California is based on EPRI's framework.

- E3 has been developing a public DER modeling tool not to pick the "best" option but rather to provide guidance to help inform stakeholders and policy makers of various options available.[20] The tool is being developed through a transparent, iterative process, incorporating as much desired functionality as possible. The tool gives users the ability to change electric design by rate class; calculate associated adoptions and output metrics; and allow advanced users to modify a wide range of assumptions. The following is an overview of the process:

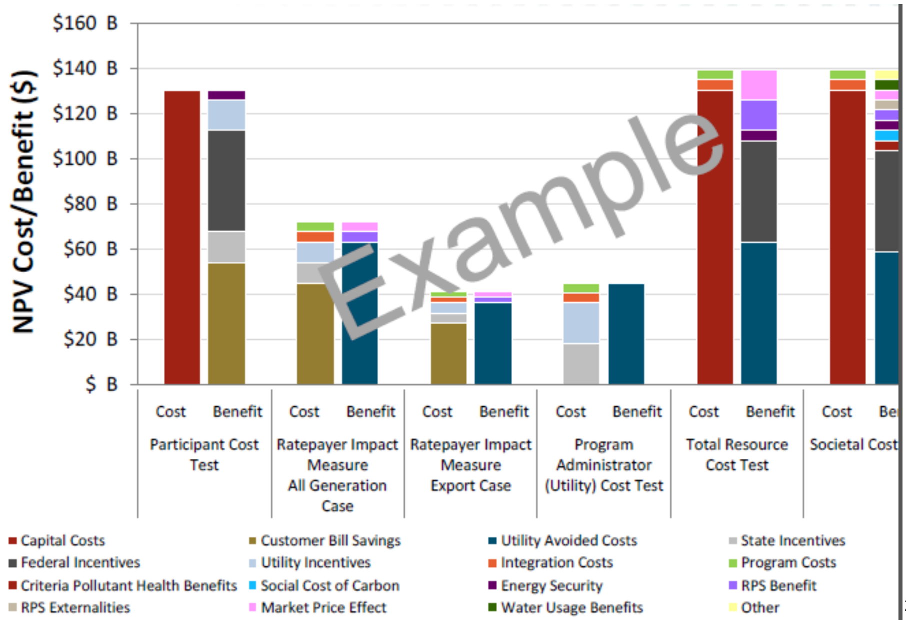


[21]

- Currently, metrics used in the public tool to evaluate the cost impacts of DERs use the following standard-practice manual cost tests:
  - Participant cost test
  - Ratepayer impact measure (using all DER generation)
  - Ratepayer Impact measure (using only exported DER generation)
  - Program administrator cost test
  - Total resource cost test
  - Societal cost test

- Each cost test calculates on a levelized ($/kWh), annualized ($/year) and absolute (NPV $) basis. The below chart is simply meant to illustrate the different outputs created using different standard tests.

[20] *Overview of Public Tools to Evaluate Successor Tariff/Contract Options*, E3, December 16, 2014
[21] Ibid, page 13



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[22] Ibid, page 19

Appendix A: Summary of NECHPI Initial Comments on the Proposed CBAF

- NECHPI supports the Commission's long-term vision of a reliable, resilient, flexible, low-carbon electric grid driven by an integrated, bidirectional set of distributed capabilities and competitive market constructs based on a real-time transactive energy system structure. This is a "big" vision and one that will take years to reach fruition. However, there are components which could be addressed now as part of the distributed-resource planning process to ensure that the steps taken are transparent, well-conceived, and tested and verified along the way. NECHPI is concerned that most of the white papers, reports and other supporting documents in the various REV proceedings provide few details to guide the development and implementation of the many required components of this big vision. As an example, there is considerable expectation on the part of the DER marketplace that there will be in relatively short order an infrastructure in place that will support real-time market signals to compensate DERs for the benefits they provide to the grid. NECHPI believe that it is an unrealistic assumption based on the guidance provided to date.

- An initial premise of NECHPI and other active parties in the many REV-related proceedings was that resolving the key issues (1) surrounding market design and platform technology development and deployment ("MDPT") and (2) establishing the Benefit Cost Analysis Framework ("BCAF") would provide substantial progress for integrating the wide range of REV-driven activities into a coherent whole. NECHPI has yet to see evidence of this. The DSIP guidance document, to be based on the MDPT Final Report issued on August 17, 2015, was originally due to be filed on September 8, 2015 and whose filing date was recently extended to October 15, 2015. The Commission also granted an extension for the required utility DSIP filings to June 30, 2016. NECHPI has repeatedly expressed concerns, including in its initial comments on the proposed CBAF, that there are no baselines or projections established through a state-wide integrated energy resource analysis and about how changes in values will be measured and validated across a wide array of programs, projects, plans and the like down to the specific DER resources on individual feeders, a necessary condition to measuring, validating and valuing progress toward specified clean-energy goals and objectives. There is sufficient time now to undertake all of the foundational work necessary to ensure the successful implementation of REV initiatives and programs.

- The proposed BCAF has been viewed throughout these proceedings since the summer of 2014 as foundational to the success of REV over both the short- and longer-terms. The Market Design and Platform Technology Working Group Report and the Clean Energy Fund Information Supplement do not mention the proposed BCAF or its incorporation into each of their cost-benefit analyses, and both the final Generic Environmental Impact Statement ("GEIS") and the recently filed utility Energy Efficiency Implementation Plans ("ETIPs") employ yet a different set of methodologies for calculating DER values and environmental impacts than the CEF. This is a clear indication of the lack of consistency between and among REV programs and initiatives and the need for clarification on the use of the CBAF to inform the screening for cost-effectiveness. Because of the incompleteness of the proposed BCAF and the many issues not addressed clearly or consistently, which is clearly evidenced by active party comments to the proposed BCAF, NECHPI strongly recommends that the Commission establish a collaborative stakeholder process to develop a robust CBAF that will be able to support REV objectives and enable the achievement of State clean-energy goals.

- NECHPI is highly concerned, particularly since there are no baselines or projections established through a state-wide integrated energy resource analysis, about how changes in values will be measured and validated across a wide array of programs, projects, plans and the like, a necessary condition to measuring, validating and valuing progress toward specified clean-energy goals and objectives, and how all of these different programs will be paid for. It is clear from the initial filed comments that active parties are highly concerned with the lack of specific and detailed financial analyses of the various options and the tradeoffs entailed with each proposed approach. NECHPI has the same concerns.

- It is currently impossible to break out the costs associated with each of the REV-related programs and to align them with current general rate cases, including utility capital-expenditure and grid modernization programs. There is simply no way to evaluate if and where there are duplicative costs, initiatives and efforts.

- Thus, NECHPI supports the requests by active parties such as Exelon Companies and the Environmental Defense Fund to initiate a new proceeding that takes a more holistic, integrative approach to the numerous REV-related proceedings and to align them with each other, with the goal of establishing standardized, transparent methodologies, protocols, and tool sets for systematically measuring the costs and benefits of each proposed program to ensure that ratepayer funds are used appropriately to achieve a reduction in electricity bills, not increases, which is currently highly likely.

- NECHPI urges the Commission to develop a rigorous CBAF methodology, tool sets and protocols using the EPRI Integrated Grid Benefit-Cost Analysis Framework approach as the foundation. Its bottoms-up circuit-by-circuit analysis forms the necessary foundation to ensure that all of the appropriate costs and benefits associated with the integration of DERs are reflected in a CBAF. NECHPI believes that the Commission needs to address this explicitly and concretely by mandating the utilities to adopt certain specified standardized and transparent methodologies, modeling tools, frameworks, templates and associated documentation to ensure that the "new" utility business models, market constructs and REV objectives are met successfully, cost-effectively and in as timely a manner as possible. In addition, it is clear that the utilities are resistant to implementing over the short-term a circuit-level analysis of their distribution systems, relying on the standard argument about security and proprietary information. However, states such as California, Hawaii and Massachusetts have successfully dealt with these issues, and New York needs to focus clearly on REV goals, which are driven by the successful scale-up of distributed energy resources, which start at the circuit level.

- NECHPI notes that many of the refinements, enhancements and other modifications in the CBAF suggested by various active parties in current reply comments are generally attempts to compensate for the drawbacks of the proposed CBAF, which is still a traditional, system-oriented treatment of average costs and benefits and not reflective of REV's emphasis on locational and temporal values down to the circuit level. EPRI's approach clearly points to the widely varying net benefits of DERs at the circuit level and that the only way to establish costs and benefits for DERs is to undertake these circuit-level analyses as the start of the analytic process. This is clearly a difficult and complex proceeding, and NECHPI agrees with the City of New York that two comment periods, which reflect the efforts of only a handful of active parties, are not sufficient for the development of a robust CBAF appropriate for REV objectives.

- In New York State, there is a host of recent proceedings as well as on-going DER programs and tariffs, some of which are being taken over by the utilities, all of which have direct relevance to the development of the utility DSIPs and each utility's internal planning processes as well as the implementation of CEF and other state DER-related programs and initiatives, many of which overlap with or are transitioning to utility-managed programs. NECHPI believes that a key to the success of meeting state clean-energy goals and REV objectives will depend on how well they are integrated into utility DSIPs, which are supposed to be designed to develop approaches and methodologies to maximize the deployment of DERs at the distribution level and to optimize their effectiveness and locational values. All of the state's and utility DER programs, initiatives and tariffs should be aligned to maximize the state's and REV's objectives.

- However, NECHPI observes that there is currently a lack of transparency on how these multiple proceedings and existing programs and tariffs will be aligned, the possibly overlapping costs associated with implementing them and the manner by which they will be integrated into the utilities' next rate cases. There is considerable concern on the part of active parties regarding the lack of transparency on budgets and proposed expenditures on all of the components supporting the scale-up of DERs.

- The preferable course of action in NECHPI's estimation is to have the Commission provide guidance to align and integrate all of REV's various proceedings, DER programs and tariffs into the DSIP process and the next general rate cases while maintaining the integrity of various Commission proceedings with already established procedures and active parties with expertise. Given the importance of adhering to fundamental rate-design principles, most particularly those of equity, affordability and cost causation, it is critically important that active parties are able to assess the economic and financial viability of the DSIPs in the context of all of the other fundamentally related programs and initiatives, most particularly the CEF given its alleged close alignment with utility initiatives, to prevent duplication of effort, conflicting priorities and duplicative economic investments.

- NECHPI believes that the adopted CBAF should be an organizing principle upon which all programs, initiatives, projects and tariffs are built and where valuation methodologies are standardized across all utilities and programs in the state.

- It should be kept in mind that EPRI's Integrated Grid framework methodology is an "end-to-end" analysis that starts with identifying individual feeder impacts and works outward to trace the consequence of those impacts through the transmission and bulk power systems. Because DER influence emanates from where the resource is interconnected, a bottom-up approach is required to identify the impacts and trace their consequences without double-counting or missing key effects. What is most important is the net outcome after all of the cause-and-effect relationships have been identified, analyzed, specified and valued.

- The final benefit-cost step in the EPRI framework monetizes the impacts and adds them to the accumulated costs and benefits to produce summary benefit-cost metrics. In addition to consolidating results, the economic analysis traces how costs and benefits arise among various entities, including utilities, customers and society in general. It is a highly comprehensive, flexible and objective approach to establishing the costs and benefits of DERs throughout the distribution system up to the bulk power system. **EPRI thus seeks a common ground for a CBAF for all stakeholders. The framework is meant to be the same regardless of the electric system, state and local policy goals, utility business practices, and regulatory oversight parameters and whose outputs can be used in any cost-effectiveness screening processes.**

- EPRI maintains that "the benefit-cost framework for the Integrated Grid establishes this sound engineering and economic foundation; from it, multiple stakeholder perspectives can be examined upon it." Critical to using new analytic tools for DER assessment is an understanding of the perspectives of all parties involved and that, while reconciling these different perspectives may be difficult, the chances of success are improved if all can share an accurate understanding of the physical and economic requirements for grid integration.

- EPRI observes[23] that utility system planning techniques need to evolve rapidly as two-way power flow continues to develop on the distribution system, which raises many issues for a variety of different stakeholders. Stakeholders see the issues from different perspectives, which may require different analysis techniques to be employed. However, in all cases, they should be rooted in the same physical causes and impacts and reflect the same utility planning practices that will adapt to the electric system's new requirements. EPRI maintains that "the benefit-cost framework for the Integrated Grid establishes this sound engineering and economic foundation; from that, multiple stakeholder perspectives can be examined upon it." Critical to using new analytic tools for DER assessment is an understanding of the perspectives of all parties involved and that, while reconciling these different perspectives may be difficult, the chances of success are improved if all can share an accurate understanding of the physical and economic requirements for grid integration. This will require a "bottoms-up" view of the electric grid.

- As a final note, on August 13, 2015, The California Public Utilities Commission issued a proposed decision adopting an expanded scope, a definition, and a goal for the integration of demand side resources.[24] NECHPI mentions this proceeding, along with the Distribution Resource Plan proceeding, R. 14-08-013, because the goal is to move utilities toward a fuller integration of distribution system planning, operations and investment and to create an end-to-end framework from the customer side to the utility side of the system (in other words, integrating what utilities offer customers, which it refers to as integrated demand-side management, and on what customers offer utilities, that is, the integration of demand-side resource, including the identification of tariffs, contracts and other mechanisms for the deployment of cost-effective distributed resources. The proceeding also recognizes that distributed energy resources provide greater value to the grid and the customer than stand-alone resources and that it expands demand-side resource to include distributed energy resource on the system side of the customer's meter anywhere within the Commission's jurisdictional (low-voltage and sub-transmission) distribution system. NECHPI believes this is significant and worth noting for the Commission's consideration in the REV proceeding, most particularly how it relates to the proposed CBAF.

- NECHPI recommends that the Commission enable the alignment and integration of utility distribution and transmission and NYISO planning efforts in order to align various proceedings as higher penetrations of DERs at all levels on the grid will have an increasing impact on the transmission and bulk power systems and their operations.

- NECHPI agrees with EDF that the focus of the LSR program should be on the reduction of GHG emissions. NECHPI has undertaken significant analysis on the experience of geographic areas (e.g., Germany and California), which have historically exclusively focused on the massive scale-up of variable energy resources such as solar PV and wind. NECHPI notes the many unintended consequences of not accounting for the complexity of the power system and the requirement for a balanced approach. NECHPI observes that there is a mistaken belief that simply installing large

[23] EPRI Integrated Grid Blog, Jeffrey Roark, EPRI economist, 7.31.15

[24] *Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Demand Side Resource Programs*, Rulemaking 14-10-003 filed October 2, 2014

quantities of renewable energy will lower GHG emissions. This has been demonstrated not to be the case.

- Appendix E presents case studies in Germany and the U.S. that demonstrate that CHP, energy storage and other flexible distributed resources are key to the reduction in GHG emissions in areas with high penetrations of renewables. Recent analysis of Germany, as an example, show a massive increase in renewables over the last 10 years but the same level of GHG emissions and much higher electricity prices during the same time period. As a result, Germany is mandating energy storage, CHP and smart inverters to counteract these unintended negative consequences. Essentially, it is the balance of distributed resources across the grid that allow for a future of greatly reduced GHG emissions. Solar PV on its own will not be able to achieve a zero-emissions future, since because of its generation variability and uncertainty, it causes indirect effects that produce higher levels of GHG emissions. Appendix G discusses the upper limits of renewables penetration and the negative consequences of higher penetration levels on wholesale markets.

APPENDIX B: Overview of EPRI's Integrated Grid Cost-Benefit Analysis Framework

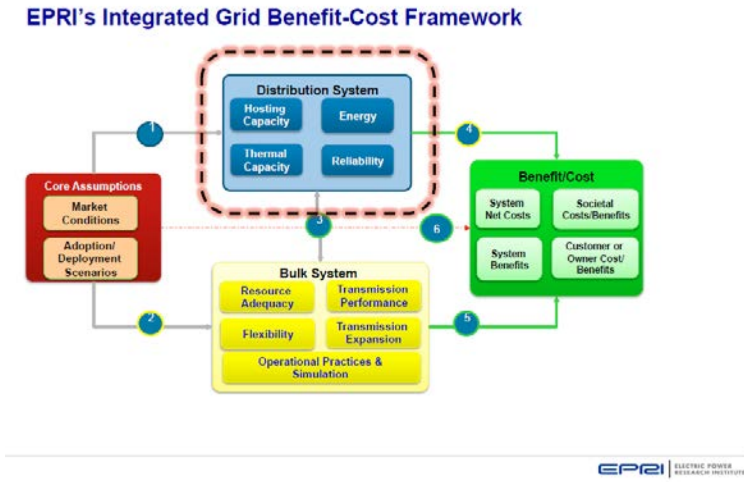
The EPRI Integrated Grid Cost-Benefit Analysis Framework has defined and developed engineering-driven tools, protocols, methodologies and approaches, rooted in the fundamentals of power system engineering and economics, necessary to conduct consistent, repeatable and transparent studies to anticipate, plan for and accommodate DERs. In turn, these studies provide a consistent valuation methodology to determine the costs, avoided costs, benefits and net benefits of DERs that enable utilities and grid operators to identify reliable and affordable ways to take advantage of the new distributed ways that electricity is produced, delivered and used at the local level. A clear goal is that its approach is applicable to all regions, systems, markets, and technologies.

<u>The framework is meant to be the same regardless of the electric system, state and local policy goals, utility business practices, and regulatory oversight parameters</u>: "Providing answers to the investment and policy questions requires a distillation of the system analyses in a way that facilitates strategic decision making: comparing and contrasting alternative portrayals of how many DERs are adopted where, as well as how the distribution and bulk power system are modified to accommodate these distributed resources…...The results inform the selection from DER integration alternatives that may have different approaches but lead to the same result: a safe, reliable system. They also inform the assessment and refinement of policy goals."[25]

Exploring both benefit and cost-causation paths related to DERs informs utilities, regulators and policy makers about the implications of proposed interconnection policies, cost-allocation methods and rate design: "A comprehensive analysis identifies how the physical system must change to accommodate DER. The EPRI Integrated Grid Framework evaluates impacts, benefits, and costs in a way that allows utilities to individually tailor a study to their circumstances and assess the most relevant alternatives. It imposes a structure that facilitates comparison of the results with what others have found. The framework does not stipulate which alternative should be pursued or how the costs incurred from those that are pursued should be recovered – that is left to the responsible stakeholders."[26]

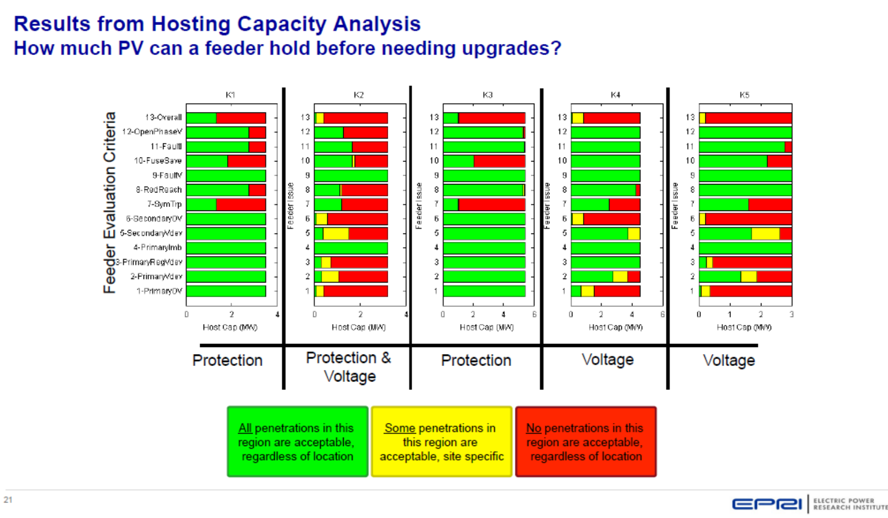
The following is a high-level depiction of EPRI's BCA framework:

[25] Ibid, page 9-2
[26] Ibid, page 9-3



EPRI's Integrated Grid framework methodology is an "end-to-end" analysis that starts with identifying individual feeder impacts and works outward to trace the consequence of those impacts through the transmission and bulk power systems. It recognizes and describes how to extend the results of circuit DER hosting capacity studies conducted at the distribution level through to the transmission level and the bulk power system and traces these benefit and cost streams from their "point of emanation to their monetary manifestation."[27] Thus, because DER influence emanates from where the resource is interconnected, EPRI maintains that a bottom-up approach is required to identify the specific locational impacts and then trace their consequences through the distribution, transmission and bulk power systems without double-counting or missing key elements: "Each feeder is unique like a snowflake, and we need to understand the attributes and how to penetrate with DER in the best possible way."[28]

The following depicts the wide range of results produced from EPRI's circuit hosting capacity analysis for five different circuits, using certain feeder engineering-evaluation criteria:

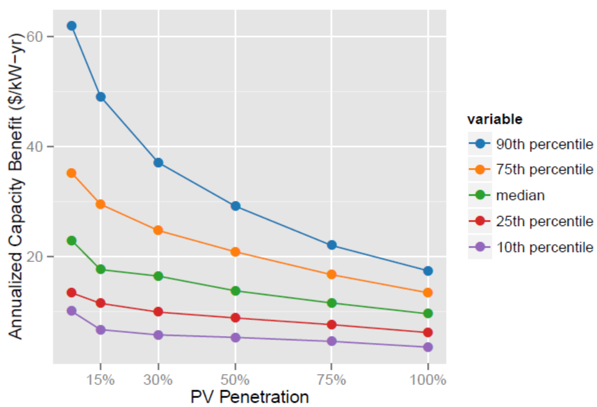


27 Ibid.

28 *Assessing the Costs and Benefits of Distributed Energy to the Grid of the future*," Utility Dive, July 23, 2015, quote by Barbara Tynan, Washington Relations Director, EPRI

Recent studies and analyses further reinforce the importance of circuit-level analysis as the key to establishing the costs and benefits of DERs and thus, a systematic, scalable and replicable CBAF. Older studies focused on broad, aggregated impacts of DERs on the system level, but few answered the question of how they support the distribution system on a circuit level. Using data from Northern California utility Pacific Gas & Electric and solar provider Solar City, researchers from the Energy Institute[29] at Berkeley's Haas School of Business modeled long-term physical and economic impacts of up to 100% PV penetration on a subset of PG&E's distribution feeders. The study's main goal was to find the value of distributed solar for distribution circuit capacity deferral (in other words, how solar could help provide power to circuits that would otherwise be needed to handle peak loads).

On average, the study found that the levelized value of deferred investment in distribution system upgrades and avoided costs is small: around half a cent per kWh ($6/kW-year). However, the analysis also demonstrated that when using disaggregated data on a circuit basis, this economically insignificant average value hides tremendous variation in feeder-specific capacity values. Capacity values are zero across a large majority of feeders where no capacity upgrades are anticipated for 10 years but for approximately 10% of the feeders, the picture looks quite different.



The above figure shows that estimated capacity values exceed $60/kW-year (or $33/MWh using the researchers' discounting and electricity production assumptions) for approximately 10% of the feeders analyzed, assuming a solar PV penetration rate of 7.5%. This is almost on par with the energy value. The median capacity value exceeds $20/kW-year. This also suggested that the value on some circuits could be a significant fraction of the installed cost of PV. Thus, the value of deferred investments in distribution system infrastructure associated with a given level of distribution generation depends significantly on how these resources are distributed on the system.

Thus, EPRI's hosting capacity modeling on a feeder-by-feeder basis is to establish a detailed characterization of the electrical operation of a circuit to establish a baseline. DERs are then added in increments until a violation occurs based on engineering criteria and defined by the deterioration of service below established standards, Mitigation strategies are then evaluated; one is selected and implemented, which restores the circuit to acceptable operations, and additional DERs are added until another violation occurs. "This sequential-load DER penetration approach establishes for each circuit the threshold for DR adoption before accommodations are required and defines the cost to extend that

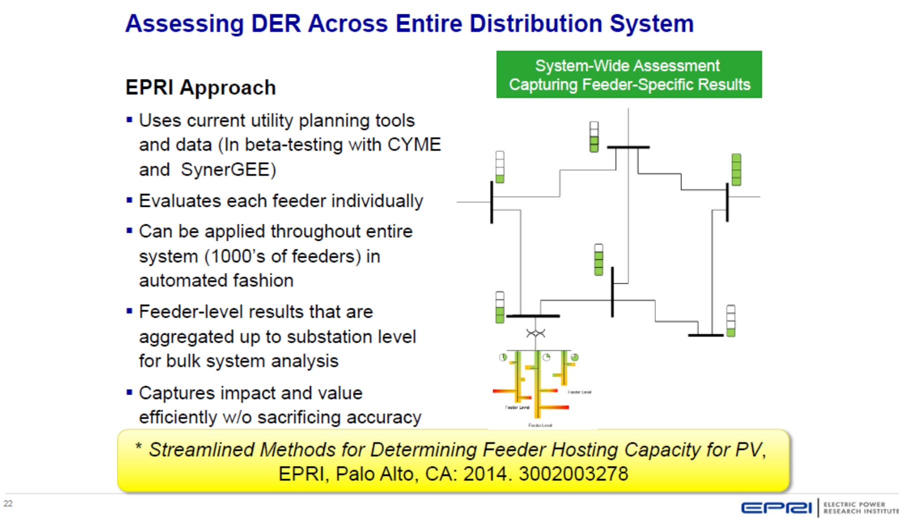
[29] *Economic Effects of Distributed PV Generation in California's Distribution System,* Energy Institute at Haas, M.A. Cohen, P.A. Kauzmann, D.S. Callaway, June 2015

threshold."[30] Thus, EPRI's hosting capacity methodology can be used to determine how a specified level and type of DER would be optimally distributed across a circuit or among circuits on a system.

Key findings from the analysis of each feeder include the following:

- Feeder-specific hosting capacity;
- Substation-level hosting capacities;
- Identification of least-cost locations for integrated DER along a feeder;
- Mitigation solutions;
- Loss impacts;
- Energy consumption; and
- Asset deferral.

<u>Building out from an analysis of the individual feeders, EPRI then assesses DERs across the entire distribution system.</u>



This approach also recognizes the interdependent nature of DER impacts on system generation planning criteria (resource adequacy), operational criteria (such as the provision of operating reserves), and transmission system design and operations. Traditional utility planning generally employs a tops-down methodology that begins by establishing possible benefits that might be attributed to DER and then to search for contributions in the form of avoided costs – e.g., avoided generation, T&D and distribution capital costs generally calculated in long-term planning studies. Establishing benefit and cost categories is essential to ensuring that the analysis finds them all and counts none twice.

> As EPRI states: "However, if the studies did not model the characteristics of DER contributions to meeting electricity demand and did not identify the electric system costs incurred to accommodate those resources, the attributed avoided costs fall short of portraying the complete net benefit picture. That representation becomes even less credible if the DERs' location on the grid and its type are not accounted for explicitly. The EPRI framework involved conducting a

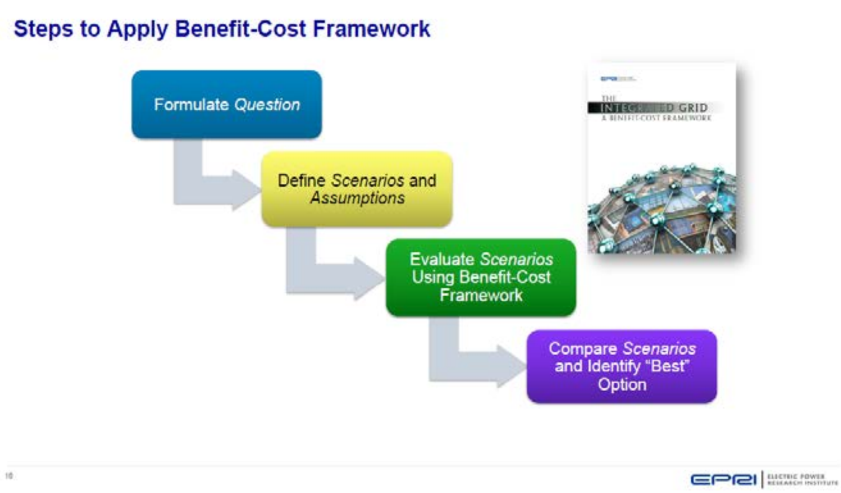
[30] *The Integrated Grid Benefit-Cost Framework*, EPRI, February 2015, page 3-5

systematic, bottoms-up simulation of the impacts associated with a specific level of DER connected to a specific location of the distribution grid."[31]

EPRI's approach thus relies on the ability to establish avoided costs individually by category, rather than calculating them systematically by examining the system as a set of complex physical and financial interrelationships starting at the feeder level. The EPRI framework employs this strategy, which, while it is close to what others have proposed, is different in that EPRI proposes identifying and quantifying impacts attributable to DER through a bottom-to-top analysis of the power system, grounded in the fundamentals of power system engineering and economic analysis.

EPRI examines the complex engineering and economic relationships that define the electric system to identify and quantify impacts that are due solely to DER interconnection. Those impacts include benefits (e.g., avoided costs) and DER accommodation costs, costs that otherwise would not have been incurred by the utility. Grounded in the fundamentals of power system engineering and analysis, EPRI's approach is methodical and systematic, using methods that are accurate, consistent and reproducible.

<u>Scenario planning and modeling</u> is also fundamental in EPRI's framework. Scenarios are alternative versions of the future distinguished by how key parameters and assumptions differ from those of the baseline and among study scenarios. Because so many technical, economic and financial variables are involved – each of which can take on many different levels – the combinations, permutations and possibilities could be overwhelming beyond what an individual study or even many coordinated studies could accomplish. EPRI has developed a methodology to limit the scale and scope of scenario modeling requirements and still produce meaningful results because it allows automated modeling a system this large with this level of detail, with the goal of isolating DER impacts, and the establishment of baseline growth projections by individual type of DER resource type.



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In California, Southern California Edison ("SCE"), in its recently filed Distributed-Resources Plan as a case in point, provides both statewide and SCE-specific projections by DER type (base load, solar PV, additional achievable energy efficiency or AAEE, demand response, CHP, EV, storage (both distribution

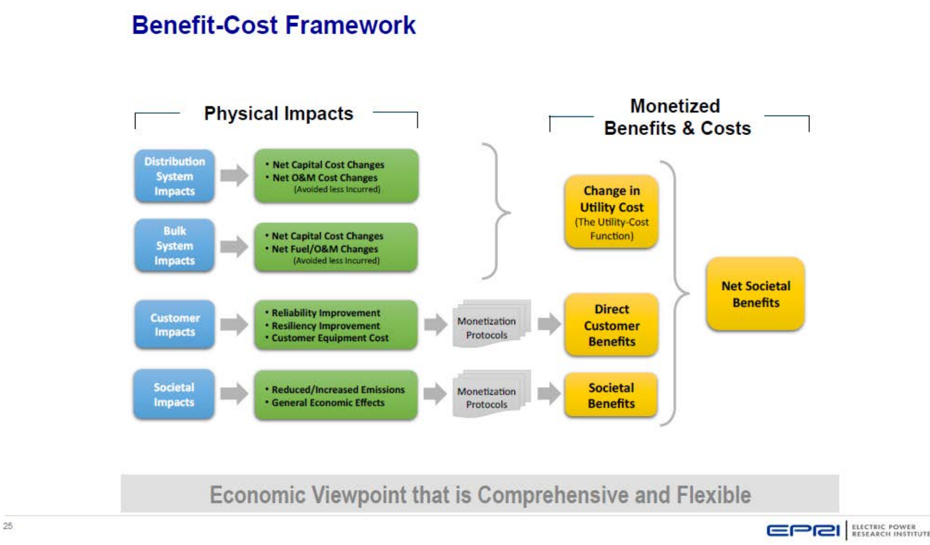
[31] Ibid, page 2-3
[32] *Value of the Integrated Grid: Utility Integrated Distributed Resource Deployment*, EPRI, EIA Energy Conference 2015, June 15, 2015

and customer-sited) and storage (transmission). SCE then make estimates of DER penetration by DER type down to the circuit level, making the assumption that DER allocations are unconstrained by any limitations on the existing distribution grid to accommodate DERs. SCE estimates are not meant to be forecasts but used for planning purposes to identify optimal DER locations from a cost-benefit perspective.

EPRI's bulk power system ("BPS") analysis involves the joint study of transmission and generation planning to establish the impacts of DER interconnected at distribution. As with distribution system analysis, BPS analysis employs a series of metrics that measure the system's reliability and performance. Given the potential for impacts in the form of costs and benefits, the operation and future planning of the bulk power system are evaluated to determine what adjustments are needed to maintain performance at acceptable levels while maximizing the value of interconnected DERs. Through an iterative process, candidate solutions can be evaluated for economic efficiency in terms of their capital expense and operating cost. Evaluating these metrics requires five interlinked processes as follows:

- Resource adequacy (sufficient generating capacity available to meet demand)
- Flexibility (sufficient balancing capability)
- Operational scheduling and balancing (successful balancing of supply and demand)
- Transmission system performance stable, high-quality power supply delivery)
- Transmission expansion (sufficient network capacity)

Then, the results derived from the distribution and BPA analyses comprise a set of impacts. Some are monetized when posted to the benefit-cost analysis by virtue of their being a cost or avoided cost that is an output of the impact analyses. The benefit-cost step monetizes the remaining impacts and adds them to the accumulated costs and benefits to produce summary benefit-cost metrics. In addition to consolidating results, the economic analysis traces how costs and benefits arise among various entities, including utilities, customers and society in general. It is a highly comprehensive, flexible and objective approach to establishing the costs and benefits of DERs throughout the distribution system up to the bulk power system. EPRI seeks a common ground for a CBAF for all stakeholders.



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[33] *Value of the Integrated Grid: Utility Integrated Distributed Resource Deployment*, EPRI, EIA Energy Conference 2015, June 15, 2015

DER impacts are physical changes to the power system that result from interconnected DERs. Impacts should be measures or estimated in any case to a reference or base case. While it is challenging to quantify all impacts, EPRI's methodology provides some methods and models to do so. Costs and benefits are the monetary/economic equivalents of impacts and are derived through a variety of monetization methods. Financially, they can be grouped into major categories that have natural association with cost causation or avoidance and further classified according to whether they are internal to the utility cost function or externalities.

EPRI generally distinguishes between net costs incurred by the utility (the utility cost function in the below chart) and are therefore collected in rates, and costs and benefits that accrue to customers and society and affect resource utilization but are not priced by the market or administratively and are therefore not included in utility revenue requirements. EPRI argues that providing the utility perspective is essential because DER accommodation may require incurring costs to realize benefits. A societal perspective is also important because we are concerned with the economic as a whole and with the welfare of a defined society, not just a specific benefit or loss to one party of the economy, one group or one person. Which externalities are monetized and which are left as measures of physical impacts are left as jurisdictional decision, though EPRI allows the incorporation of those values in its framework.

The cost-benefit analysis methodology and protocols convert the technical impact data produced in conducting a detailed DER impact study into a summary metric of the net benefits. This informs decision makers of the relative merits of alternative DER integration approaches: "An important distinction in comparing scenarios (different DER penetrations, for example) is between societal net benefits and utility revenue requirements. The former is appropriate for assessing public policy to ensure that scarce societal resources are used optimally. Externalities used in that calculation must be removed before comparing the implications for the utility revenue requirements and rates that recover it."[34]

The following is a table of the impacts of DER accommodation and possible benefits and costs:

[34] *Value of the Integrated Grid: Utility Integrated Distributed Resource Deployment*, EPRI, EIA Energy Conference 2015, June 15, 2015, page 9-125

Distributed Energy Resource Impacts

Element	Impacts	*Benefit*	*Cost*
Distribution	Loss Reduction	x	
	Capacity Upgrade Deferral	x	
	Reconductoring		x
	Line Regulators/STATCOMS		x
	Relaying /Protection		x
	LTC accelerated wear		x
	Voltage upgrade		x
	Smart Inverters	x	x
	O&M		x
Bulk Power System	Generation Mix/Requirement Changes	x	x
	Deferral of Transmission Upgrades	x	
	Transmission losses	x	
	O&M	x	x
	Fuel Savings	x	
	Congestion	x	
	System Operations/Uncertainty		x
Customer	DER Investments		x
Societal	Emissions - CO2/GHG, Hg, SOx, NOx	x	
	Cyber Security	x	
	Health	x	
	Macroeconomic effects	x	

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Elements of the utility-cost function include distribution loss reduction, upgrade deferrals, redonductoring, new required equipment on the feeder or substation (e.g., voltage regulators), protection changes (relaying), accelerated wear on load-tap changes, voltage upgrades, smart inverters and energy storage. Bulk power system impacts include generation mix changes, transmission loss reduction, operations and maintenance, fuel consumption, congestion, and emissions.

Customer and societal impacts are generally referred to as externalities, namely costs that a utility does not usually incur. Because these impacts are not yet transacted in a market, there is no unambiguous measure of their value or cost. Customer costs and benefits include long-lived purchases such as energy efficiency devices and investments such as storage and rooftop PV system. Some costs reduce the customer's electricity usage while others may improve the quality of service in terms of improved reliability or resiliency. Because the costs are incurred voluntarily by the customer, their purchases presumably have value to the customer. Impacts that affect society, on the other hand, may be physically measurable but not unambiguously monetized. Examples include a reduction of emissions such as CO2 that result from DERs replacing fossil fuel-burning generation and positive or negative changes in macroeconomic measures of social wealth, such as jobs and wages, which result from DER supplied energy replacing the output of central generation resources.

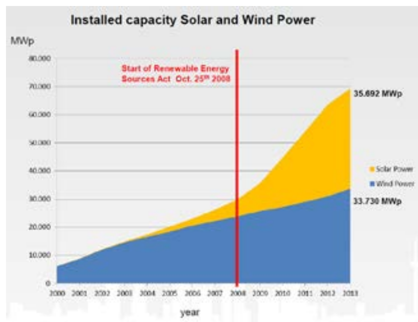
Reliability, resiliency and flexibility also have values, but costs may not yet be identified by either the utility or its customers or it is not straightforward to put a dollar figure on it in every case, particularly at a feeder level. The EPRI DER accommodation methodology identifies when and how these impacts will be triggered and then defines mitigating actions and their costs. These are than able to be counted as part of the DER accommodation cost or its benefit.

APPENDIX C: Importance of Combining Renewables with Flexible Resources such as CHP, District Energy and Energy Storage

German and U.S. Case Studies

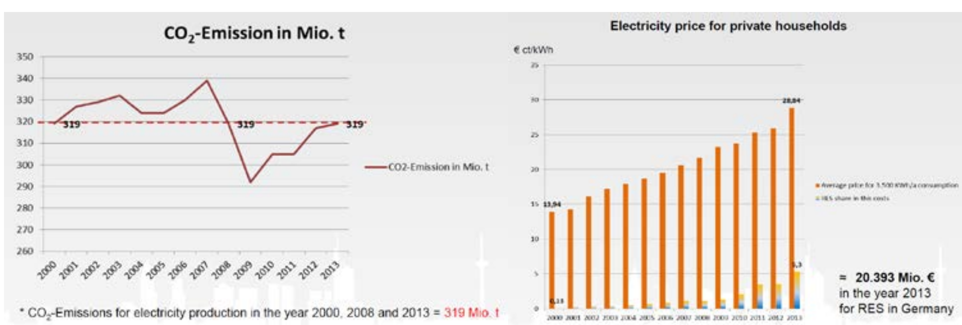
Germany's success story, "Energiewende," demonstrates clearly the necessity of combining renewables with flexible resources such as CHP and district energy. In a presentation at the IDEA Conference in Seattle on June 9th, 2014, Werner R. Lutsch, Managing Director of AGFW, an independent association promoting energy efficient, district energy and CHP at national and international levels, discussed the unintended consequences of Germany's rapid increase in renewable energy on Germany's grid. His conclusion was that the current regime had led to:

- An extremely fast and steep development of solar and wind power



But

- The same high CO2 emissions as 15 years ago
- The lowest electricity market prices at the EEX (electricity stock exchange)
- The highest consumer prices for electricity ever
- A lot of wasted money, bankruptcies and unemployed people in the solar industry in Germany
- Intense competition between renewable energy and energy efficiency.

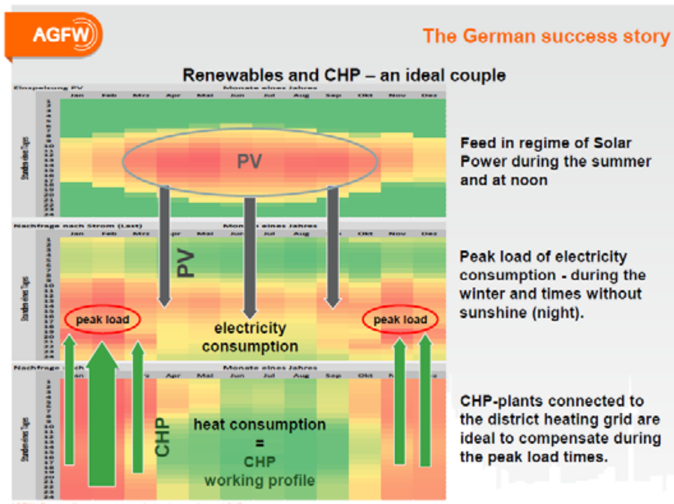


He argues that CHP and DHC are answers to Germany's dilemma. They combine efficiency, flexibility and renewability for the heating, cooling and electricity markets to form a smart, multi-functional platform. The combined technologies are able to:

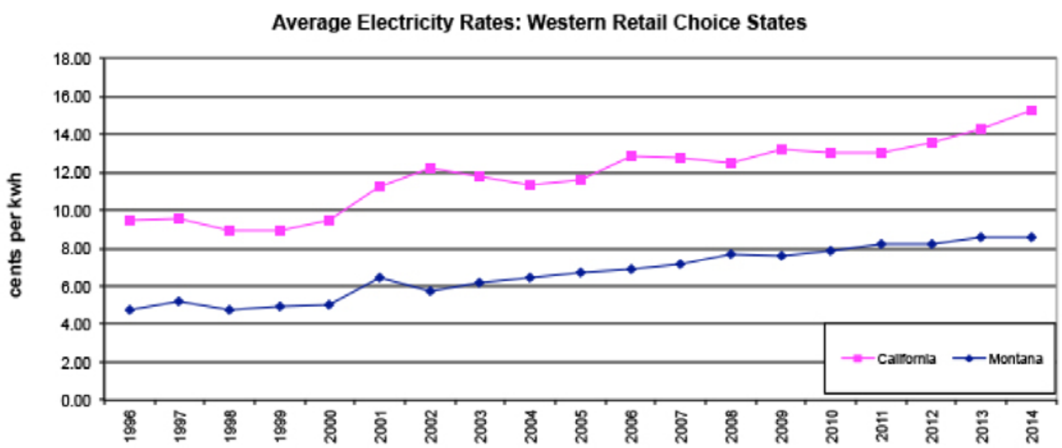
- Give more flexibility to the renewable electricity market;
- Provide integration services via power-to-heat;
- Support CO2 emissions reduction targets;

- Secure renewable energy sources for the heat market;
- Create local jobs and added value to communities; and
- Shape the energy concept, Energiewende, as citizen-friendly.

He concludes by saying that renewables and CHP is an ideal couple, not competitors, as seen in the chart below.



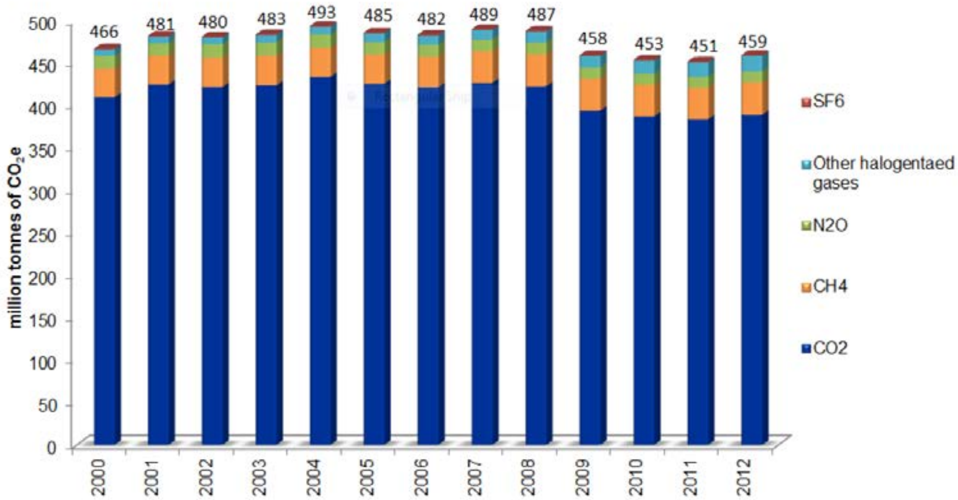
California is faced with the same dilemma: rapid increases in renewables penetration levels but increasing utility electricity prices and comparable levels of CO2 emissions levels in spite of the rapid increase in renewables. It should be noted that rates have gone up substantially in 2015, and the May 2015 EIA report has retail rates increasing from under $16.00/kWh in 2014 to $17.35/kWh.



[35]

Per the following chart, CO2 emissions declined somewhat but have started to rise again and are almost at 2000 levels.

[35] *2014 Retail Electric Rates in Deregulated and Regulated States* , April 2015, American Public Power Association



[36]

CHP, District Energy and Energy Storage as Key Contributors to Renewables Integration, Grid Operational Flexibility and GHG Emissions Reductions under Scenarios of High Penetration Levels of Variable Energy Resources

Because of their flexibility and enhanced efficiency, cogeneration and district energy systems can play a relevant role in an integrated energy system by providing a sustainable option to help balance a greater share of variable renewable energy sources. CHP and district energy are complementary technologies that can exist separately but when combined together, they offer states and utilities a unique set of tools to meet COE emissions-reduction requirements while providing substantial additional benefits, including more reliable heat and power supply, the chance to utilize local and renewable fuel sources and reduced energy costs.

In addition to their turndown range and capability (that is, the degree of flexibility in the generation unit), cogeneration technologies can operate within a range of power-to-heat output ratios, allowing units to adapt to specific energy demand requirements over time. The addition of energy storage capacity to cogeneration plants can also provide an added level of flexibility to regulate electricity and heat outputs while minimizing energy losses. These technologies can use a wide range of energy of energy sources, from fossil fuels to waste and renewable sources, such as biomass, solar and geothermal energy.

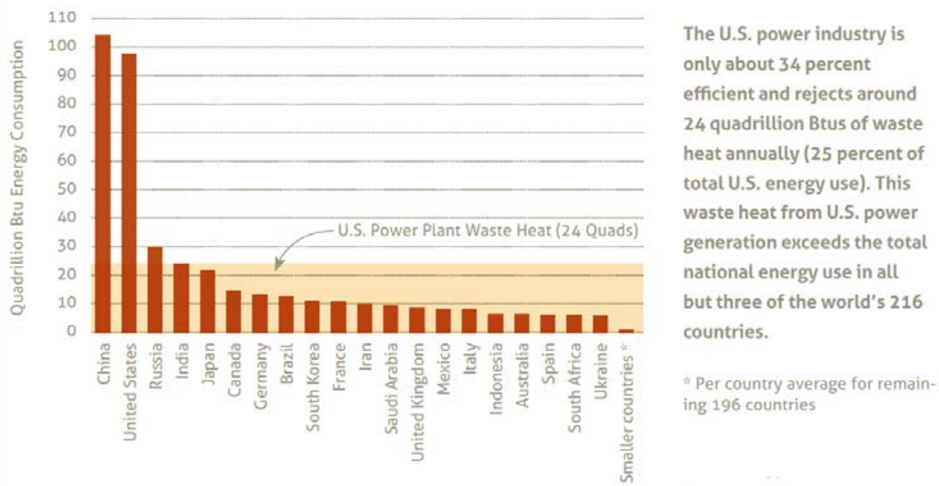
Flexible technologies as stand-alone units are not as effective in improving the carbon footprint of energy systems as those integrated into an efficient and sustainable energy system. Diverse options exist to manage digital-energy interactions between generation, distribution and end uses, but these interactions need to be better integrated into business structures in a market that is increasingly decentralized with multiple actors and bi-directional interconnections. By incorporating other technologies, such as heat pumps and thermal storage capacity, DE networks can also help to mitigate peak demand electricity loads by providing alternative heating and cooling options.

Europe is an excellent example of an integrative approach and has been more forward-thinking than the U.S. about the integration of thermal energy and heating and cooling into its energy ecosystems. Heating and cooling accounts for nearly half of the final energy consumed in the European Union. Today, more than 50% of all building stock in some countries of Northern Europe is connected to district energy systems, and CHP systems make up a high portion of district energy systems in countries such as

[36] *Greenhouse Gas Emissions by Gas 2000 through 2012*, California Air Resources Board, 2014 Edition

Finland, Denmark and the Netherlands. In the energy-intensive U.S., the amount of waste heat exceeds the total national energy use of all but three of 216 countries. (International District Energy Association, IDEA2015 Annual Conference)

FIGURE 1. Comparison of U.S. Power Plant Waste Heat to Total Energy Use in Other Countries.



Source: Data from U.S Energy Information Administration, International Energy Statistics (2011 data), http://tinyurl.com/kkfnavt.

The European Commission has recently stated that the combination of improved end-use performance and optimized heating and cooling supply through the more intelligent use of efficient technologies such as cogeneration and district energy would allow a much more cost-effective energy transition. In fact, an emerging trend is a “mix-and-match” solutions strategy which will include integrated demand-side management, energy efficiency, CHP systems, demand response, storage and renewables to create a more customizable but replicable and scalable suite of energy solutions. It is expected that there will be increased need to adopt integrated systems that incorporate distributed energy resources such as CHP, energy efficiency and energy storage in order to balance the variability of renewable energy resources.

In 2013, the United Nations Environment Programme (“UNEP”) initiated research on and surveyed low-carbon cities worldwide to identify the key factors underlying their success in scaling up energy efficiency and renewable energy as well as in attaining targets for zero or low greenhouse gas emissions. District energy systems emerged as a best-practice approach for providing a local, affordable and low-carbon energy supply. A conclusion of its research is that district energy represents a significant opportunity for cities to move towards climate-resilient, resource-efficient and low-carbon pathways. UNEP argues that the development of modern, energy-efficient, climate-resilient and affordable district energy systems is one of the least-cost and most-efficient solutions for reducing greenhouse gas emissions and primary energy demand. A transition to such systems, combined with energy efficiency measures, could contribute as much as 58% of the carbon dioxide emission reductions required in the energy sector by 2050 to keep global temperature rise to within 2 – 3 degrees Celsius.

In 2014, the International Energy Agency (“IEA”) published *Linking Heat and Electricity Systems: Cogeneration and District Heating and Cooling Solutions for a Clean Energy Future.* Its introductory paragraph states: “Cogeneration technologies and efficient district heating and cooling (“DHC”) networks provide clear environmental benefits due to their enhanced conversion of energy and use of waste heat and renewable energy sources. Cogeneration and DHC can also serve as flexible tools to bridge electrical and thermal energy systems, which will play an increasingly important role in achieving integrated, sustainable energy networks in the future. These technologies can therefore be an essential part of strategies for greenhouse gas ("GHG") emissions mitigation and energy security.

CHP plants are able to be designed to be as flexible as possible and able to operate in multiple modes and with multiple different fuels. When following electrical load, for example, it can be run as an intermediate peaking plant and can be started and loaded very quickly, in well under 10 minutes. At the same time, it can be run in baseload. Using a multi-engine installation concept means that any number of engines can be run to match load, allowing high overall plant efficiency to be maintained.

Smart CHP is also about having a generating facility that is able to run on almost any type of fuel. This can be beneficial to on-site facilities in terms of security of supply and economics. Being able to switch fuels is very important in situations, for example, where there is a possibility of interruption to the main fuel supply. CHP is able to use natural gas, waste heat recovery, anaerobic digesters, biomass, synfuels and other biofuels as fuel sources.

A recent Netherlands energy-market simulation study in 2014 showed that going forward, with a huge amount of renewable-energy production coming on-line, there will literally be only room for flexible power. A conclusion of the study was that small-scale, natural gas-fired CHP plants could especially provide the flexibility services required by the grid in the future because of their capability to start up to full power in a few minutes and to handle a quick restart after shutdown.

As a result, NREL lists the following keys to unlocking these "smart CHP" flexibility benefits:

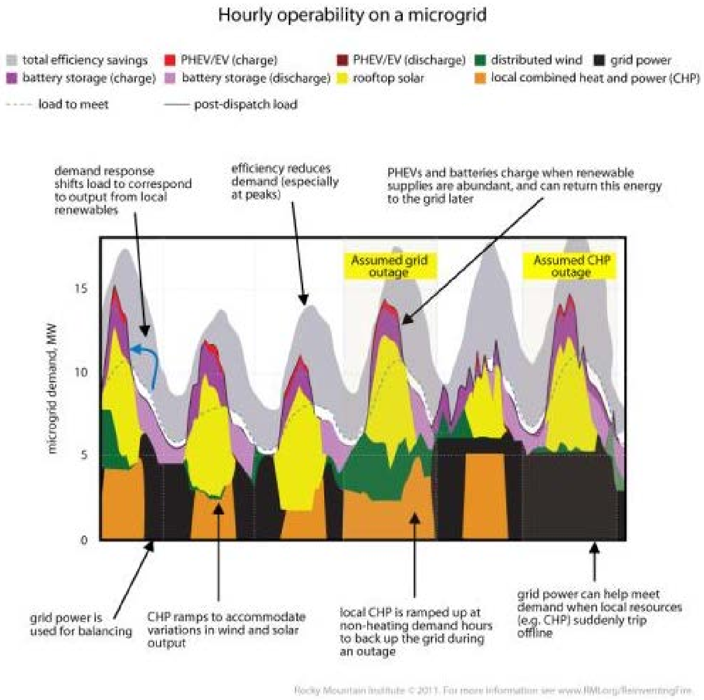
- Enhance plant turndown limits (e.g., down to 10% of maximum capacity as in many Danish CHP plants, instead of 50% of maximum capacity as in many China CHP plants);
- Invest in thermal storage and bi-directional energy flow to enable greater decoupling of heat and power production; and
- Establish market signals to incentivize optimal utilization of CHP capabilities, especially dynamic prices that more accurately reflect hourly or sub-hourly supply and demand balance.

In addition to larger sized CHP units, thermal storage coupled with CHP systems will be a key technology solution going forward to be able to provide flexibility and a variety of grid services. Under the appropriate market conditions and access to new revenue streams, Regulatory Assistance Project in an October 2014 presentation, *Big Changes Ahead: Impacts of a Changing Utility Environment*, provides support for thermal storage as a very cost-effective technology to provide CHP and DHC systems with additional capabilities needed by the grid going forward as intermittent variable generation resources increase. Thus, RAP states that CHP/DHC, coupled with thermal storage, will be highly capable of providing a variety of grid services while supporting customer loads.

It should also be noted that Rocky Mountain Institute in a 2011blog on microgrids notes that if a microgrid has sufficient dispatchable supply and demand-side resources and storage capacity, these can enable the integration of a large percentage of local variable renewable energy.[37]

[37] Accessed 8/13/15 (http://www.rmi.org/RFGraph-hourly_operability_on_microgrid)

Hourly operability on a microgrid



Thus, this microgrid example illustrates the need for a full suite of resources – dispatchable resources such as CHP, demand response (both load-shifting and load-reduction), energy storage and a viable grid connection – to balance the output from distributed variable renewables.

Provision of Ancillary Services. Ancillary services are today almost exclusively delivered by conventional power plants, though this varies from ISO to ISO in the U.S. Overloads lead to shutdown of fluctuating generators – despite their marginal costs of near zero – before conventional power plants are shut down. Substituting conventional power plants in the field of power balancing and ancillary services is therefore essential for reaching goals in expanding renewable energy. Fluctuating generators have very limited potential to deliver positive control reserves while next-generation CHP can play a significant role in this substitution with regard to power balancing as well as ancillary services. Next to the balancing of demand and generation on a regional level, local grid problems are expected to play an increasing role and will create a massive need for the expansion of distribution networks if there is no intelligence in the feed-in of decentralized generation to balance generation and consumption at the local level.

Princeton University, in several recent publications, discusses the benefits of microgrids and CHP as a key component to support the economics in particular of its campus microgrid. At the IDEA evolving ENERGY Conference in Toronto, Canada on October 28th – 30th, 2014, Ted Borer's presentation, *Resilient Community Microgrids – Concepts, Operations and Maintenance,* specifically discusses the tremendous economic and carbon footprint-reduction benefits that CHP provides to its microgrid. He points out that the microgrid reduces both energy use and peak demand; and CHP greatly increases energy efficiency; provides self-sufficiency and support places of refuge in emergencies; lowers real-time power costs for all customers; and distributes risk into smaller pieces, substantially improving grid reliability. Princeton also earns significant revenue revenues from the provision by its CHP plant of ancillary services to PJM.

Synergies between Natural Gas and Renewables. In spite of the fact that natural gas and renewables are often considered competitors in markets, in actuality, natural gas and renewable energy each contribute to economic growth, energy independence, and carbon mitigation, sometimes independently and sometimes collectively.

A recent paper commissioned by the Joint Institute for Strategic Energy Analysis and written by the National Renewable Energy Laboratory, entitled *Exploring the Potential Business Case for Synergies between natural Gas and Renewable Energy*, focuses on how compelling business models can be created where these two domestic forms of energy work in greater concert. The paper explores revenue opportunities for utilities, end users and project developers that emerge from system-level perspectives in bulk energy and in four distribution-edge subsectors: industrial, residential, commercial and transportation end uses.

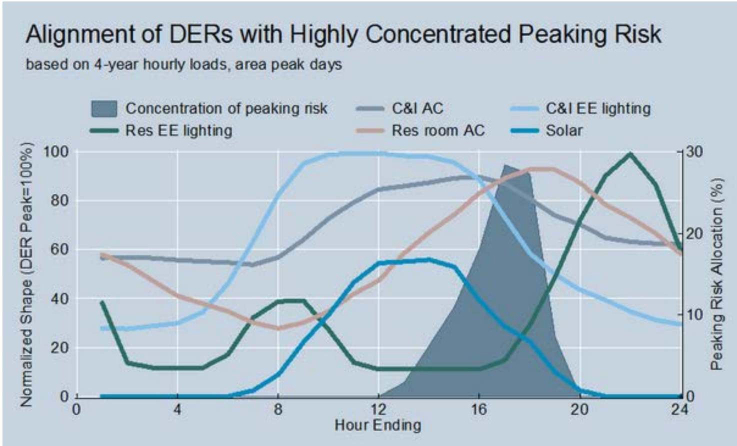
A key underlying concept is that a rising share of variable generation in the system has increased the need for the remainder of the capacity – both on the supply and demand side – to complement flexibly the variable output. In systems with a high share of variable renewables, lower predictability in the market as well as for network operators implies a **high need for flexibility** to cope with this volatility. On an individual asset level, flexibility is the modification of generation injection and/or consumption patterns in reaction to an external signal (price signal or activation) in order to provide a service within the energy system. The parameters used to characterize flexibility include the amount of power modulation, the duration, the rate of change, the response time, the location, and so on.

This report emphasizes that synergies between natural gas and renewable energy are found at multiple levels – from hybrid systems that optimize assets (e.g., smart buildings with both PV and CHP) to transmission corridors that serve both technologies. The business models that capitalize on both renewable energy and natural gas can access new revenue streams, including wholesale market opportunities for the distribution edge (e.g., demand response aggregation), upstream and downstream arbitrage opportunities from shared infrastructure, and energy services that offer the customer resiliency, reliability and reduced costs.

A set of potential business drivers leverages gas and renewable use at the distribution edge. There are multiple technology solutions available that build from the potential synergies, such as islandable energy systems, microgrids, on-site CHP, alternative transportation fuels, and others. Questions concerning maximizing value streams of the synergies between the two at the distribution edge include the following:

- What technology pathways are most promising for optimizing natural gas and renewable options for industry, commercial sites, homes, vehicles, communities and others?
- What combination of natural gas and renewable energy services address multiple, or all, energy services demands? What are the business case and impact metrics for these versus non-coupled energy services?
- How can larger industries optimize the use of natural gas, renewable energy and industrial demand to increase financial performance?
- What are the synergies from distributed renewable energy with distributed natural gas and how can firms prepare for changes in their business models?

There are a number of other justifications for risk diversification through the implementation of a portfolio of distributed energy resources. The concentration of local peaking risk and the alignment of specific DERs will vary by location. Many engineers and other stakeholders believe that the grid will need the right mix of resources at the right location and in the right time periods. DER value depends greatly on how well operating characteristics of DER align with local demand-management needs. The following are excerpts from an article in Intelligent Utility e-newsletter:[38]



This chart serves to emphasize several key points, which reinforce SCE's portfolio approach to optimize resources and capabilities on a circuit-by-circuit basis at the lowest costs possible.

- The specific operational characteristics of different DERs influence their value at each location. DERs are not a single type of resource that can be easily defined and include a wide range of technologies with diverse operating characteristics. To provide value, the specific production/reduction characteristics of a DER must align with the local peaking pattern.

- Mr. Bode maintains that the whole is more important than the parts: "Many DERs deliver incomplete solutions for local distribution capacity relief needs when deployed individually but have characteristics that can provide complementary value when deployed as a combined solution. In the right combination, DERs deliver more value as a whole solution than as stand-alone components. Because of this, distribution capacity relief using DERs is not a simple commodity but a complex problem that may require optimizing the portfolio procured based on cost, DER attributes and local peaking patterns. The diversity of DERs and local needs are the main challenges for integrating these resources. This same diversity is also DERs' key strength. When bundled together in the right combination, DERs deliver more value than as stand-alone components.

- EPRI's Integrated Grid BCAF provides an optimization approach at the feeder level through to the bulk power system to identify where and when different types of DERs, and in what combinations, provide locational values.

[38] *What locational value do DERs provide to the grid?* Intelligent Utility, Josh Bode, Principal Consultant, Nexant Energy, August 3, 2015, www.intelligentutility.com/print/423995

APPENDIX D: Effects of Large-Scale Solar and Wind Geneation on Wholesale Markets

Recent studies[39] serve to emphasize the critical importance of understanding the effects of large-scale solar generation on different generation mixes in the wholesale electricity markets over a medium-to-long-term time frame. In broad terms, both MIT and the Breakthrough Institute analyze how a significant penetration of solar generation could affect operations, planning and market prices in electric power systems at the wholesale level. It is now generally thought that a marginal-cost-based market mechanism will not make sense in the context of high solar penetration since prices will frequently be zero (or even negative if solar output is subsidized on a per-kWh basis), and new investments in necessary conventional generation will not be financially viable. Thus, even though solar has boundless technical potential and significant economic potential, it may be limited by its impacts on wholesale electricity markets.

Key summary findings of the MIT Study are as follows (See studies for detailed analysis.):

- When PV systems deploy rapidly, the rest of the technology mix does not have time to adapt.
- Massive solar PV deployments can condition the future configuration of the generation mix and have significant impacts on wholesale prices.
- Price reductions from solar PV production are systematically the most significant during the same hours when solar generators deliver maximum output. As a consequence, higher levels of solar penetration lead to lower revenues per kW of installed solar capacity. For this reason, at any given per kW installation cost of solar PV, there is a system-dependent threshold or limit beyond which adding further increments of PV capacity will not break-even from a cost perspective.
- Key flexible technologies such as energy storage and CHP, when configured with renewables, can play key roles in managing wholesale prices at high levels of renewables penetration.
- With a large penetration of solar PV, incremental PV does not significantly reduce the annual net peak load of the power system. In regions where electricity demand peaks after sunset (and particularly during the winter hours), adding PV generation with energy storage does not reduce annual peak load at all.
- A large penetration of solar PV displaces the plants with the most expensive variable costs (e.g., fossil-fuel generators) and increases thermal plants' cycling requirements (being forced to change their output more frequently to meet load ramps associated with large changes in net demand, they have to decrease production to the minimum stable load for a higher number of hours, and they also have to start up and shut down more frequently).
- These two operational changes also affect short-term price dynamics and the "merit order effect," which tends to reduce wholesale electricity prices. The impact of increased solar PV penetration on market prices and plant revenues depends on the pre-existing generation mix.
- In general, the higher the penetration of solar, the larger the system's operating reserve requirements, leaving less flexible plants to meet system demand. This reduces overall system flexibility.
- At high levels of solar PV penetration, it will be increasingly necessary to curtail production from solar facilities (and/or from other zero-variable-cost generators) to avoid costly cycling of thermal plants.

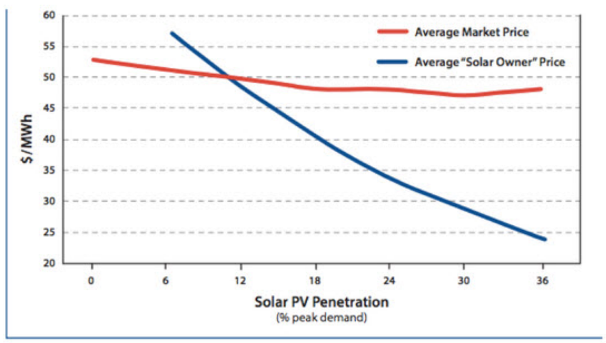
[39] *MIT Study on the Future of Solar Energy*, Energy Initiative, Massachusetts Institute of Technology, 2015; *A Look at Wind and Solar: Parts I and II*, Breakthrough Institute, May 26 and 27, 2015

- Even if solar PV generation becomes cost competitive at low levels of penetration, revenues per kW of installed capacity will decline as solar penetration increases until a breakeven point beyond which further investment in solar PV would be unprofitable
- Positive synergies can be achieved by jointly coordinating dispatchable resources and solar production in ways that help reduce net peak loads and cycling requirements for thermal generators. A flexible resource can also increase the capacity value of solar generators at low levels of PV penetration.
- Production-based incentives (such as per-kWh incentives) lead to more inefficient and costly operation decisions in the short term and to a more inefficient generation mix in the long term. They can reduce the economic curtailment of output from solar and other renewable generators and lead to inefficiently high levels of solar energy production in systems with large amounts of PV capacity.

Breakthrough Institute findings are similar (since one of authors of the MIT study is at the Institute), but several additional points are worth noting:

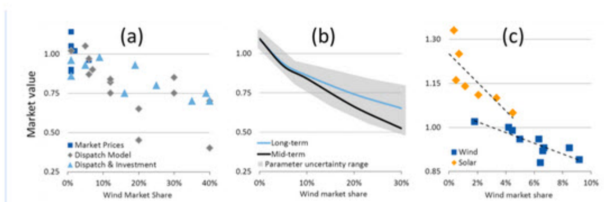
- Because wind and solar generate regardless of price, they bid into the market at zero and take whatever the clearing price is. If there is enough wind and solar, they start pushing other bidders out of the market due to what is called the merit order effect. With large amounts of wind and solar, the system breaks down. Imagine an hour when the whole system runs on wind and solar, and all bidding is zero. Then the clearing price would be zero, and nobody would get paid, including wind and solar generators.
- There are clear reasons to expect the share of variable energy resources in system-wide electricity mixes to be constrained. The authors argue that it is increasingly difficult for the market share of VERs at the system-wide level to exceed the capacity factor of the energy source. For wind power, this typically ranges between 20% and 40%, while for solar, it runs between 10% and 25%, depending on the quality of the renewable resource and its location.
- The challenges of integrating VERs into the grid (i.e., the increased system flexibility needed to handle the wider variations in power system output necessitated by fluctuating wind and solar output) have been widely reported. The authors believe that system integration costs will not be the cause of a slowdown in renewables penetration; rather, the fundamental economics of supply and demand will likely be the limiting factor. When renewable energy earns its keep in the energy market and is not supported outside the market by incentives, subsidies and feed-in tariffs, the revenues wind or solar earn in electricity markets decline steadily as their market shares grow. The authors provide the following from the MIT Future of Solar study as an illustration of merit order effect of increasing levels of solar PV on the system:

Figure 8.11 Average Market Prices and Average Prices as Perceived by Owners of Solar Generation



Source: MIT Future of Solar *study, Chapter 8.*

To further illustrate the point, the following illustrates the same dynamic as the market share of wind power rises as well. The figure below depicts the decline in the "value factor" or the ratio between the market prices earned by wind generation and the average market price (effectively the ratio between the blue and red lines in the MIT figure above) as wind penetration grows. (The rightmost graphic below also includes solar, which experiences a more rapid drop in values, though it starts at a higher level.)



Wind value factor estimates from a literature review (a), the numerical model EMMA (b), and German historical market data (c). The value factor (wind revenue over base price) decreases with higher penetration rates.

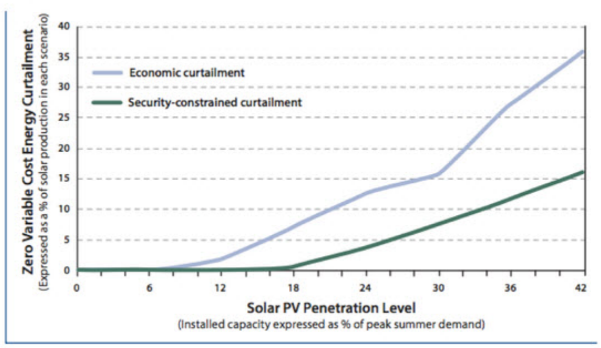
Source: Lion Hirth, "The market value of variable renewables: The effect of solar wind power variability on their relative price," Energy Economics (2013).

- A conclusion drawn from the analysis is that if renewable energy is ever to become truly subsidy-independent, it means that there is a natural stopping point at which a marginal increment of wind or solar will become unprofitable. The market revenues earned by these VERs will eventually fall far enough that it is no longer worth deploying more. This is why the idea of reaching "grid parity" is meaningless: as soon as wind or solar penetration grows, the goal posts move farther away due to the merit-order or market-price effect. Wind and solar costs will have to keep falling to secure greater penetration levels and remain profitable at the every lower and lower market prices caused by increasing VER penetration.
- Alternatively, if wind and solar are to remain subsidized, the amount of public subsidy per unit of energy supplied will have to keep growing in order to push VER shares higher and higher. The total subsidy cost could rise sharply, as the price per MWh required increases alongside the quantity of electricity generated from these sources.
- While the merit-order price-suppression effect could limit the maximum wind and solar penetration on its own, the authors cite a second, even more challenging effect which enters into the equation at the point where wind or solar reaches a market share equal to its capacity factor. At that point, output from the resource will regularly vary between 0% and 100% of total electricity demand. At that point, wind or solar output will have to be regularly curtailed or spilled as VER

supply will begin to routinely exceed demand. In fact, it will be both economical and necessary for stability, reliability and security reasons to curtail wind or solar long before they reach 100% of system-wide electricity demand at any given hour.

- According to a major new study[40] on the challenges of integrating wind and solar in the Western Interconnection of North America, the maximum production of variable renewables at any instant cannot exceed about 55 – 60% of total demand without risking system stability. In Ireland, which is currently one of the world leaders in VER penetration, system operators currently limit VER production to 50% of demand at any given time.
- The following (from the MIT Future of Solar study) illustrates how both economic and system security-related curtailment rises rapidly as solar penetration reaches its capacity factor in a Texas-like power system:

Figure 8.5 Economic Curtailment of Zero-Variable-Cost Energy



Source: MIT Future of Solar *study, Chapter 8.*

- As the figure illustrates, security-related curtailment picks up precisely as solar's share equals its capacity factor (about 18% in Texas) while economic curtailment begins well before that point. The same dynamic holds for wind power as well, although it tends to have a higher capacity factor and less "peaky" production profile, which may reduce the amount of economic curtailment compared to solar. This matters because even a small percentage of curtailment can quickly ruin the economics of a solar or wind project.
- The authors believe that the capacity factor threshold will become increasingly important in the discussions about the eventual roles of wind and solar in various electric grids. While the authors' insights are primarily derived from modeling the impacts of VER on the grid, they argue that as wind and solar shares grow in a variety of real-world power systems, the dynamics will soon become realities.
- The capacity factor threshold, therefore, implies that wind may eventually be able to provide on the order of 25% to 35% of a power systems' electricity, while solar may top out at 10-20% in most regions. DOE's ambitious vision calls for wind to provide 20% of America's electricity by 2030 and 35% by 2050. However, even at that scale, it is clear that wind and solar alone will fall short of decarbonizing the electricity system, let alone the full energy sector. This is where the capacity factor threshold is most important: to consider the contribution of wind and solar to a fully decarbonized power system, which is an essential component of any credible plan to confront climate change.
- At the upper end, the threshold indicates that wind and solar may be able to supply anywhere from a third to a half of all electricity needs. This leaves the job half-done. It is precisely why the

[40] *Western Wind and Solar Integration Study Phase 3 – Frequency Response and Transient Stability*, National Renewable Energy Laboratory, December 2014

authors are concerned when conversations about decarbonizing the power system become overly focused on a "renewables-only" path forward. Wind and solar will be important contributors to a low-carbon planet, but they cannot do the job alone. An honest, pragmatic conversation about decarbonization necessitates that tough questions be asked about how various technologies fit together to achieve decarbonization. The authors state: "We are quite doubtful that a renewables-only path is the most technically or economically feasible or desirable path to a high-energy, low-carbon planet. It's well past time for a much more nuanced discussion about the role wind and solar will play in global power systems."

Lawrence Berkeley National Laboratory reports serve to emphasize the above points:

- A Lawrence Berkeley National Laboratory report found that, while solar has high value at low levels, the value drops off as more solar comes on the grid. By the time it reaches 15% penetration levels, it has half the value; at 30%, it has only a quarter of the value. In contrast, concentrating solar with thermal storage fares better, keeping two thirds of its value at 30% penetration; wind, since it derives most of its value from displacing energy instead of capacity, retains more value even at levels over 40%.[41]
- More solar, absent energy storage, means less marginal value, in part because more solar does not provide any more peak-reduction benefit. At high levels of penetration, solar has already wiped out the daytime peak, shifting it to non-solar times, so the marginal value of the next kilowatt-hour of solar, at least for offsetting generating capacity, approaches zero.
- Essentially, the authors view that to compensate for the merit order effect, there has to be large subsidies to make solar viable. The spot market reveals market fundamentals, and actual payments to solar generators is a policy question, not an economic one. Over the short term, wind and solar generators will be able to sell directly to buyers and stay out of daily markets. There are still buyers who do not want to be exposed to the risks of spot markets. However, over the longer term, as spot market prices fall due to large amounts of solar and wind energy, more buys will be tempted to play in short-term markets, which will begin to drag down the value of long-term contracts: "All markets will converge over time. Without a policy motivation, in the long term, the markets will tend to value solar like the spot market does."
- Miller and Wise of LBNL did a follow-up study in 2014[42] to examine ways of mitigating the declining marginal value of solar and wind. They found a wealth of options, including geographic diversity of wind siting, technological diversity (through combinations of technologies), more flexible sources of generation, bulk power storage and shifts in demand subject to real-time pricing. A key conclusion is that if solar is going to achieve high penetration levels, then there will have to be a completely different temporal pattern of demand and prices. The potential decline in value is real but it is also "a clarion call for how, when and where we use energy."

[41] *Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study in California*, Andrew Mills and Ryan Wiser, Ernest Orlando Berkeley National Laboratory, June 2012
[42] *Strategies for Mitigating the Reduction in Economic Value of Variable Generation with Increasing Penetration Levels*, Andrew Mills and Ryan Wiser, Ernest Orlando Berkeley National Laboratory, March 2014

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Appendix E: Comparison of 10 MW CHP, Wind and Solar Plants

The following comparison provided by ICF International serves to emphasize that CHP provides substantial benefits, including GHG emissions reductions, when compared on an apples-to-apples basis. (It should be further noted that the comparisons would be ever more compelling if the CHP system were using a biofuel.) Again, NECHPI provides this information to ensure that there is a fair and honest treatment of CHP as a key component to the realization of clean-energy future and the decarbonization of the State's economy. In fact, as a critical grid-integration technology, CHP, either natural gas-fueled or with a biofuel, can enable much higher penetration levels of variable energy resources than would otherwise be possible.

Category	10 MW CHP	10 MW PV	10 MW Wind
Annual Capacity Factor	85%	22%	34%
Annual Electricity	74,446 MWh	19,272 MWh	29,784 MWh
Annual Useful Heat	103,417 MWh_t	None	None
Footprint Required	6,000 sq ft	1,740,000 sq ft	76,000 sq ft
Capital Cost	$20 million	$48 million	$24 million
Annual Energy Savings	316,218 MMBtu	198,563 MMBtu	306,871 MMBtu
Annual CO_2 Saving	**42,506 Tons**	**17,824 Tons**	**27,546 Tons**

Based on: 10 MW Gas Turbine CHP - 28% electric efficiency, 68% total efficiency
Displaces National All Fossil Average Generation (eGRID 2010) -
9,720 Btu/kWh, 1,745 lbs CO_2/MWh, 6% T&D losses

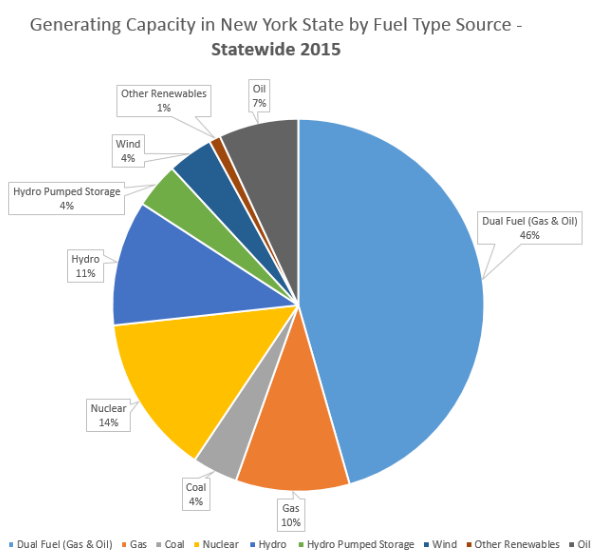
APPENDIX F: NYISO Power Plant Statistics

The following is an excerpt from an on-line analysis, *New Report Highlights Huge Role of Natural Gas in New York Energy Plan*, Joe Massaro, August 6, 2015.

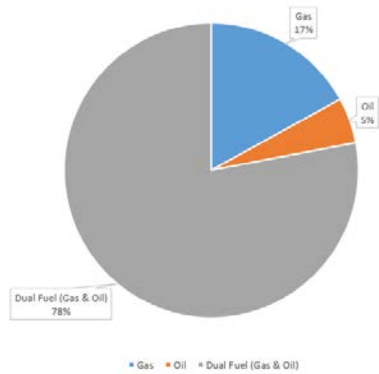
The New York Independent System Operator (NYISO) recently released its 2015 Power Trend report, which looked at the long term planning for the state's electric power system. The following represents a summary of a section of the report, "Growing Reliance on Natural Gas":

- Power projects using natural gas (gas-only and dual-fuel units capable of using either natural gas and/or oil) account for 56 percent of New York's generating capacity**.**
- More than 70 percent of all proposed generating capacity in New York is natural gas or dual-fuel power projects**.**
- Winter 2014 price spikes, driven by increased cost of natural gas delivered to New York, increased the average wholesale electric energy price to $69.30 per megawatt-hour in 2014, up from $59.13 per megawatt-hour in 2013. Winter 2015 saw less volatility and lower costs as a result of improved fuel supplies and enhancements to gas-electric coordination**.**
- The NYISO and its stakeholders are exploring the creation of additional market-based incentives for fuel supply assurance during periods of summer and winter peak demand that can stress both the electric and the natural gas delivery systems.

The below charts show the generating capacity for New York state and New York City by fuel type in 2015.



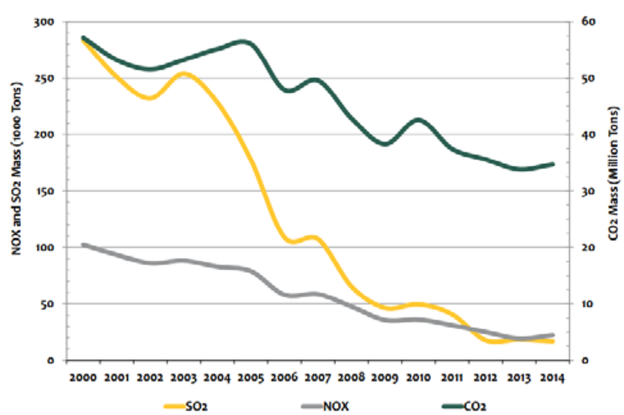
Generating Capacity in New York State by Fuel Type Source - **New York City 2015**



Aside from a welcomed decrease in energy costs, the report also highlighted [emissions reductions] New York has seen since it started using more natural gas for electricity generation. According to the NYISO report:

From 2000 through 2014, New York power plant emission rates dropped by double digits. SO2 emissions rates declined 94 percent. NOX emission rates declined 78 percent. CO2 emission rates declined 39 percent**.**

Figure 28 - New York Emission Rates from Electric Generation: 2000-2014



Data Source: U.S. Environmental Protection Agency

APPENDIX G: Resource Value Framework Worksheets

The following is an example of a worksheet to undertake a cost-benefit analysis of a DER under the Resource Value Framework. It presents all impacts, both benefits and costs in one place.[43]

Monetized Impacts (Direct Monetization or Proxy Values)				
Perspective	**Benefits**	**Present Value**	**Costs**	**Present Value**
Utility Customers	Avoided Energy Costs	$ -	Program Administration, Marketing, Evaluation	$ -
	Avoided Line Losses	$ -	Incentives Paid to Participants	$ -
	Avoided Generation Capacity Costs	$ -	Capital Costs	$ -
	Avoided Decommissioning	$ -	Increased Energy Costs	$ -
	Wholesale Market Price Suppression	$ -	Increased Environmental Compliance Costs	$ -
	Avoided T&D Costs	$ -	Integration Costs - Distribution	$ -
	Avoided Environmental Compliance Costs	$ -	Integration Costs - Transmission	$ -
	Avoided Ancillary Services	$ -	Integration Costs - Ancillary Services	$ -
	Reduced Utility Operations Costs	$ -	Distribution System Platform Costs	$ -
	Proxy Value of Risk Benefits	$ -		
	Total Benefits to Utility Customers	$ -	**Total Costs to Utility Customers**	$ -
Participants	Other fuel savings	$ -	Capital Costs	$ -
	Water & Sewer	$ -	Annual O&M Costs	$ -
	Proxy Value of Non-energy benefits	$ -	Proxy Value of Transaction Costs	$ -
	Proxy Value of Non-energy benefits	$ -	Proxy Value of Non-Energy Costs	$ -
	Total Participant Benefits	$ -	**Total Participant Costs**	$ -
Society	Tax impacts from public buildings	$ -	Tax credits	$ -
	Total Societal Benefits	$ -	**Total Societal Costs**	$ -
TOTAL	**Total Monetized Benefits**	$ -	**Total Monetized Costs**	$ -
	Utility System Net Present Value:	$ -	**Utility System Benefit-Cost Ratio:**	
	Societal Net Present Value:	$ -	**Societal Benefit-Cost Ratio:**	

Non-Monetized Impacts		
Perspective	**Impact**	**Quantitative Values or Comments**
Utility Customers	Contribution to Market Animation	e.g., program expected to promote market for rooftop PV
Society	Economic development	e.g., job-years, or gross state product impacts
	Reduced environmental impacts	e.g., impacts of CO_2 emissions not monetized above
	Increased environmental impacts	e.g., increased CO_2 emissions from fossil generation from DR

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The following applies a multi-attribute decision analysis ("MADA") to the results of the above cost-benefit analysis to factor in weightings of various factors. This increases the level of sophistication of the CBA.

RAW DATA	Net Present Value of Monetized Costs and Benefits		Contribution to Market Animation		Economic Development (Job-Years)		Non-Monetized Environmental Benefits	
	(Millions)	*Weight*	*(Qualitative Score)*	*Weight*	*(Estimate)*	*Weight*	*(Qualitative Score)*	*Weight*
Alternative A	$\boxed{\$1.47}$	0.65	Low (= 1)	0.15	615	0.10	Low (= 1)	0.10
Alternative B	$1.11	0.65	High (= 3)	0.15	2189	0.10	Med (= 2)	0.10
Alternative C	$0.98	0.65	High (= 3)	0.15	1753	0.10	High (= 3)	0.10

NORMALIZED DATA	Net Present Value of Monetized Costs and Benefits		Contribution to Market Animation		Economic Development (Job-Years)		Non-Monetized Environmental Benefits		Overall Score
	Normalized	*Weight*	*Normalized*	*Weight*	*Normalized*	*Weight*	*Normalized*	*Weight*	
Alternative A	$0.41	0.65	0.14	0.15	0.13	0.10	0.17	0.10	**0.32**
Alternative B	$0.31	0.65	0.43	0.15	0.48	0.10	0.33	0.10	$\boxed{\mathbf{0.35}}$
Alternative C	$0.28	0.65	0.43	0.15	0.38	0.10	0.50	0.10	**0.33**

[43] *Benefit-Cost Analysis for Distributed Energy Resources in New York: A Framework for Accounting for All Relevant Costs and Benefits,* Synapse Energy Economics, Prepared for Advanced Energy Economy Institute, October 2, 2014, Tim Woolf

Appendix H: Integration of Real-Time Emissions and Grid Data Analysis

There are technology platforms emerging that integrate real-time emissions and grid data analysis to turn price-responsive assets into emissions-responsive assets (e.g., to be able to turn down facility/household energy use during times of high-emissions grid power).[44] As an example, WattTime, a not-for-profit based in California, has developed a device currently for EV chargers, which is a Wi-Fi-networked and cloud-controlled charger, coupled with eMotorWorks' price-sensitive charging controls. The solution is able to schedule overnight charging to reduce its emissions profile by as much as 50% compared to the standard approach. While NECHPI is not suggesting that the State mandate implementation, the approach should be evaluated as part of an effort to make locational, circuit-based analysis of DER contributions as concrete as possible.

The platform is applicable to other distributed technologies. The focus of the approach is based on temporal and locational factors and searching for where the "marginal plant" is for the resource within that localized framework. (A marginal power plant is the generation resource on top of the "stack" of all sources being called into play to meet grid demand at that moment, whether it is a coal- or natural-gas-fired plant or a wind or solar farm.) The approach is built on work underway at Yale University, Carnegie Mellon University and University of California at Berkeley and is centered on analyzing data from the U.S. EPA's Continuous Emission Monitoring System and real-time data from the Open Access Same-Time Information System, the federally mandated platform that allows data exchange between regional grid operators. Combining the data from the two platforms allows WattTime to develop forward-looking projections of what marginal CO2 emissions will be on a per MWh basis at 5-minute intervals. While there are still numerous challenges to extensive to enumerate here, this kind of detailed, circuit-based information could help utilities align their grid investments and resource planning with their CO2 reduction goals.

While NECHPI is not yet recommending that utilities adopt such an approach at this time, it believes that an investigation of such a tool would be one important step in localizing the measurement and validation of GHG emissions costs and benefits.

[44] *WattTime Pinpoints the Greenest Grid Power*, Greentechmedia.com, Jeff St. John, July 31, 2015, http://www.greentechmedia.com/articles/read/watttime-pinpoints-the-greenest-grid-power

Appendix I: Summary of Active Party Comments on the CBAF

The following are NECHPI's summary observations on various active party comments. These are not exhaustive but represent an analysis of those of particular relevance to NECHPI:

- <u>City of New York</u>
  - Concepts proposed in Staff White Paper require further development. "The City respectfully urges the Commission to limit implementation steps related to the REV to consideration of demonstration projects,,,,,,,,until the BCA framework is improved, adopted and applied. Other projects, programs and initiatives should be permitted to proceed only after they are demonstrated to be cost-effective.
  - The City respectfully requests that the Commission establish a specific timeframe for development of the BCA so that a full and thorough analysis can be completed without unreasonably delaying the implementation of other REV-related initiatives.
  - There needs to be a full assessment of the potential benefits and impacts on the proposed changes on reliability, affordability, accessibility, security, economic development and environment.
  - There should be a single, state-wide BCAF with common analytics. A consistent framework with common analytics should decrease the potential for "gaming" the BCA to produce a positive analysis for particular DER projects.
  - The City is concerned that the adoption of separate handbooks for each utility service territory could lead to different approaches or different analyses of the same project, program or initiative across the State. While the City appreciates that the actual costs and benefits may vary, the manner in which the BCA is performed and the manner in which each such cost and benefit is treated should be uniform state-wide. Additional valuation components identified in a standard framework should be analyzed to capture unique location and project-specific costs and benefits, and the BCA should be applied in a manner that allows for the assessment of the cost-effectiveness of particular projects, programs and initiatives.
  - There can be no doubt that Staff did not utilize a comprehensive, uniform BCA analysis in its evaluation of the utility demonstration projects. The Commission should not allow any additional projects or programs to proceed, nor should it allow any expansion of the scope of demonstration projects, until data is collected and analyzed and the BCAF is completed and adopted.
  - The MDPT Report lacks any information regarding the anticipated costs that customers will bear in the implementation of the DSP platform. The same BCAF intended to value projects and programs proposed in the utility DSIPs should be considered for the development of the DSP.
  - "Throughout this proceeding, the City has raised concerns about the lack of any BCA supporting Staff's proposals and the Commission's decision. Instituting A BCA policy and framework after many decisions are made is neither an adequate nor a reasonable approach." All REV implementation should be subject to the same valuation standards.
  - Speed should not come at the expense of a full and thorough BCA of REV initiatives.
  - **"A matter as important as the BCA framework for an entire new construct of the electric industry in New York warrants far more process and input from interested parties than two rounds of public comment spread over a short span of time (and in which requests for additional time were denied."**
  - The White Paper failed to discuss the proposed duration of potential benefits. In order to accurately measure benefits of any DER measures, it is critical to evaluate the expected

duration of the benefits achieved. In performing BCAs, the Commission and utilities must take into account the relative useful lives of the DER versus the utility infrastructure. The proposed BCAF does not do so.
  - The inclusion of wholesale market price benefits is speculative at best. Any calculation of the impact a particular REV project may have on market prices, in isolation, is likely to produce inaccurate and unreliable results.
  - The use of CARIS pricing is misplaced and likely to produce questionable and erroneous results.
  - Any estimation of the value of a DER project must be location specific. Such an approach will produce a more accurate value estimation while encouraging project placement in areas of the system with the greatest need.
  - The City recommends that the various approaches to valuing carbon be evaluated, with the valuation methodology developed after due consideration of that evaluation and discussion of the available alternatives. This matter is best addressed via the collaborative process proposed by the City.
  - Since the REV is about moving away from a regulatory paradigm to a market-based construct, the universe of renewable resources should be those defined as such by the marketplace, not a regulatory proceeding.
  - The proposed BCAF seems to omit all other forms of externalities than GHG emissions.
  - Costs associated with REV implementation should be analyzed to the same extent and in the same detail as benefits. The White Paper discusses specific costs only sparingly.

- New York Geothermal Energy Association ("NYGEA")
  - There is a complete "siloing" of electric and thermal issues.
  - It is crucial to clarify the role of thermal measures in the BCAF, including how benefits and costs will be evaluated in a fuel-switching context.
  - There are no established values provided that can be used in calculating true costs.
  - "Unless an accepted means of establishing and projecting externalities for fuel consumption in New York's buildings is established, the benefit-cost analysis framework will remain incomplete and of questionable utility."
  - Once values are agreed upon, the Commission needs to put in place a process to continuously review and update them.

- Peak Power
  - The BCA understates the drivers of participant DER costs, which are critically linked to program design, regulatory certainty and asset characteristics.
  - By including a realistic and dynamic assessment of the drivers of DER project costs, especially the costs and tenor of project capital and the crucial links back to revenue certainty and program uptake and administrative costs, the BCA will be more accurate and create more cost-effective programs.
  - The BCA should work toward "universal materiality standards." There is little explanation in the white paper of why some benefits and costs are emphasized while others are simplified away. "Large drivers of value, like employing a universal versus specific discount rate (an enormous driver of value, as the White Paper notes), and line losses at on-peak versus off-peak times (yielding 5-20% differences in value), are clearly material, yet seem summarily simplified out, at the risk of losing basic accuracy. On the other hand, very small costs within Ancillary Services (about 1% of all-in average NYISO price per kilowatt-hour) seem to require consideration for every DER. A goal of the BCA should

be establishing transparently and explicitly why and when these small factors matter and to retain variables that have a major impact on value."

- "Discount rates and investment horizons vary dramatically between society, utility and DER provider; conflating all three creates unrealistic expectations and wasted or insufficient resources in incentivizing and managing DER. Oversimplifying discount rates into a single input will create counterproductive distortion between BCA-level planning and the real world."
- There are three distinct layers of evaluation from value to price signal to DER response, and discount rates should be applied at each step.
    - In order to establish value, each potential benefit and cost should be evaluated at the discount rate of the entity that would otherwise absorb these avoided costs. For example, the lifetime costs of a ton of CO2e should be discounted back to the year of emission at least at the societal discount rate.
    - To convert value to a price signal, the value established in step 1 is then considered in the context of practical capture. The relevant discount rate at this stage is that of the administering entity (most likely the utility). By factoring in expected program costs, risks and targeted net benefits, the value of the tone of CO2e, calculated per the previous paragraph, can be converted into a price signal to DER. (At this point, the value or credit ascribed to reduced CO2e emissions may be calibrated or deemed immaterial based on the likelihood of these reductions.
    - In the final step, the entity investing in the DER project (owner, investor, utility, etc.) will apply its own discount rate to the price signal in determining the optimal use of capital and operating funds and the viability of various technology and equipment options.
- Using a single, standard utility WACC for all three steps ignores program- and project-specific risks: technology risk, site control issues, single-decision regulatory changes, etc. that accompany specific projects therein.
- "The risks of oversimplifying with a single discount rate are especially market in less mature markets such as demand response where building owners effectively demand 1 to 3 year paybacks (20% to 100% discount rates) for DER, a far cry from the regulated WACCs that fall into the high single digits."
- It is likely that a higher discount rate for the later steps is and should be a part of the process. The more clearly and explicitly this increased discount rate is expressed, the better.
- "Any incremental complexity created by using impact-appropriate discount rates seems minor (and complementary) in the context of BCA and REV goals of evaluating energy system options with appropriate granularity. Documenting BCA assumptions and directing Staff and/or utilities to maintain a public and exhaustive list of variables and values can further mitigate any potential confusion."
- Why is particulate matter excluded and what is the rationale?
- Given the many tradeoffs inherent in valuing CO2e, will Staff include "embodied energy and emissions" in the BCA versus GHG emissions associated with fossil-fired generation alone. Some materiality threshold is prudent here.
- Participant levels are often a decisive factor for program cost effectiveness, particularly given fixed administrative costs for new or nascent programs. The relationship between program administration costs, participant DER costs and program benefits should be modeled dynamically, with appropriate input from market participants, rather than treated as largely independent inputs.

- The 75% of incentives as an approximation of participant DER costs is inappropriate across the universe of DERs since costs can vary substantially. As future incentives become more certain, project sizes increase, and markets mature, valuation will likely transition from simple paybacks for building owners to risk-adjusted internal rate of return.
- Staff should encourage utilities to recreate decade-scale, IRR-driven DER investment cases for solar PV and CHP rather than the short-term mentality driving demand-response's current, year-to-year value proposition. "This means retaining an allocation for building owner opportunity cost but also increasing the focus on project capital."
- The tenor (investment horizon) and cost (discount rate) of project capital is a function of many of the individual items discussed in these comments, including: 1) incentive and regulatory certainty (long term contracts/price floors and clear emissions rules, e.g.) and 2) counterparty risk and credit quality (utility vs. New York State vs. market participant, and ultimately feeds back to the system benefit from DER (as a nonwires alternative to conventional utility investment, e.g.).
- "An explicit, long-dated commitment to incentive programs and rates (with performance guarantees) can dramatically reduce project cost of capital and increase the probability that these resources can act as true substitute for conventional utility capital expenditure. A DER expected to reliably replace a long-term capital asset should have a long-term price signal."
- Creating asset-specific participant DER cost estimates would be a useful exercise of each utility's BCA handbook value of different resource types.

- National Resource Defense Council ("NRDC")
  - The utilities should coordinate with each other, Staff, the Commission and NYSERDA to develop the details of the BCAF.
  - The Commission should provide more guidance in the development, contents and application of the utility-specific handbooks.
  - The Commission should mandate that the handbooks include the same content, structure and format and that a standard template, including a detailed outline with required tables and charts for appropriate data, be developed for all utilities.
  - The DSIP process should include criteria to evaluate the quality of the DSIPs themselves.
  - The utilities should never use RIM but should conduct bill-impact studies to identify long-term bill impacts of DER scenarios.
  - The BCA should use a societal costs test, using a societal discount rate.
  - The BCAF should include estimates of any and all costs associated with third-party DER vendors.
  - Non-energy benefits are especially important for programs directed to the low- and moderate income and multifamily housing segments.

- AEE Institute ("AEEI")
  - AEEI does not support RIM; there are other options for evaluating customer bill and rate impacts.
  - There needs to be more detail on how different benefit-cost tests will be used in decision-making, investment, planning and tariff development.
  - The White Paper lacks a discussion of how the BCAF will be applied to actual utility investments and tariff development, and there needs to be a uniform application to them.
  - The SCT, with a societal discount rate, should be primary.
  - The same BCA approach and assumptions should be used by all utilities.

- AEEI recommends the addition of the following: distribution system voltage management, power factor improvement, avoided T&D investments for reliability and resiliency enhancement and avoided noise and odor pollution.
- Wholesale market price impacts should be included.
- AEEI supports valuing emissions based on estimating actual marginal damages from emissions and the addition of other externalities such as land and water use impacts. It does not support staff's approach to non-energy benefits, which are deemed as insufficient. There needs to be a more complete rigorous approach for including NEBs in the BCAF.
- Staff's approach is quite conventional, and AEEI would like to see a more innovative approach taken.
- The distinction between tariff-driven outcomes and utility investments may not be appropriate. Staff should reconsider the distinction.
- Dynamic tariffs may introduce a level of uncertainty that discourages the very DER deployment the Commission is looking to support.
- The locational and temporal aspects of REV are expected to be complex.
- A fully transparent methodology and associated assumptions used to calculate values should be uniform across the state, established through a collaborative statewide process.
- Utility BCA handbooks should include a wide range of DER technologies and should also focus on valuation of services provided to and needed from the grid. AEEI recommends that they be updated every 3 to 4 years.
- The BCA needs to study variations of output of the BCA model in relation to uncertainty of various inputs. This is an essential tool for testing the robustness of assumptions and the results of the model.
- Levels of risk by technology and project must be accounted for in the model.
    - DER options or portfolio of options are likely to have low risk profiles because cost and performance are well known at the time of investment.
    - "Properly accounting for risk benefits of DER investments should lead to a significantly lower discount rate being used."
- AEEI argues that the BCA should measure actual benefits and costs resulting from the deployment of DER rather than relying upon other markets developed for different purposes (e.g., RGGI, RPS RECs, etc.).
- AEEI disagrees with Staff's approach to add full marginal damage cost estimates to DER's pecuniary costs per MWh. Instead, the difference between emissions resulting from DER and emissions avoided from the bulk power system should be calculated and then an appropriate net adders should be applied to the DER.
- The selected approach should treat emitting and non-emitting distributed generation differently, as well as different emitting DERs, and account for differing emissions levels.
- Technologies that help methane mitigation should be valued on a CO_2e basis.
- AEEI recommends the inclusion of other environmental benefits: avoided land resource impacts, reduced water and sewerage use, water quality benefits, other heating fuel benefits, noise and other pollution benefits.
- AEEI argues that incorporating non-energy benefits reduces resource bias in program and portfolio decision-making and more appropriately directs investments of millions of public and shareholder dollars.
- AEEI discusses the Resource Value Framework as an approach to adopt.
- AEEI states that a much more nuanced approach to participant DER costs is required.
- Focus should be on those projects which provide the most net benefits to the grid.

- Association of Affordability ("AEA")
    - The BCAF should be finalized in conjunction with Track II proceedings.
    - Tariffs and other dynamic price signals must reflect more near-term assessments versus investments or long-term procurements.
    - "In the context of REV, we do not see tariffs as fundamentally distinct and do not think the application of the BCA should be different."
    - The Commission should apply the BCA to a portfolio of energy efficiency offerings.
    - The utility-specific handbooks should use consistent methodologies for determining values and include a broad range of DERs (while actual values will differ).
    - The BCA and the handbooks should be flexible to incorporate advanced in the quantification of benefits/costs and new products and services.
    - Values for combination DERs need to be included.
    - It is not useful to have all non-energy benefits and costs lumped together in one line.
    - AEE supports the including of wholesale price impacts.
    - In addition to including GHG emission externalities, the Commission should include the impacts on land and water use and quality.
    - "Omitting some benefits presumably because reliable values are not available leads to computational bias in benefit-cost ratios (e.g., the omission of net-benefit categories but not the omission of costs) and, as a result, a bias in decision-making using those ratios."
    - Non-energy costs should only be included if non-energy benefits are included.
    - AEA references the Resource Value Framework as an important methodology.

- Vote Solar
    - The societal cost test, using a societal discount rate, should be primary test employed.
    - The BCA should include wholesale price impacts and use damages-based calculation for valuing externalities.
    - The BCA should minimize the reliance on qualitative measures of non-energy benefits and externalities to the greatest extent possible.
    - Until such time as detailed analyses on economic impacts are completed (to include direct, indirect and induced effects), the BCA should not identify and "cherry-pick" subsectors of the overall New York economy for inclusion.
    - Prices in the wholesale market have no impact on changing customers' behavior.
    - The focus on wholesale price suppression is too limited in scope to include in the BCA.
    - The monetary amounts will change over time, as well as DER energy and capacity values. The benefits of DER should be appropriately accounted for over time.

- Pace Energy and Environment Center
    - The White Paper should address how the BCAF will be applied in the process of REV implementation.
    - BCAF development should be a continuing process rather than a single Commission decision.
    - There is insufficient guidance by which the BCAF will be used to inform distribution planning, the valuing of behind-the-meter resources and the adapting to changing technology markets. What costs most appropriate for each DER, for different markets and applications, for different types of investments? What tests are most appropriate under what scenarios? What outputs should the BCAF facilitate?

- The SCT should be the primary test but a staged process should be employed that uses other tests. By applying a different lens of analysis to different stages of decision-making, the BCA process as a whole could capitalize on the strengths of each test.
- The SCT should be modified to better support " the new, market-mobilizing focus that REV aims to achieve."
- Rate-impact studies should be substituted for RIM.
- Full life-of-investment analysis does not speak to how extended analysis should be weighted.
- The stated overall objective of REV in the Commission's order is of "ensuring that New York meets and exceeds its targeted goals to reduce emissions through energy efficiency and clean power development in a manner that ensures grid reliability and resiliency while enhancing the value of the system for consumers."
- Significance of externality values vary among resource options.
- Utilities should collaborate on developing a common methodology.

- Clean Coalition
  - The BCAF needs to be developed with a degree of specificity required to derive market prices and be consistently applied to different scales and types of investments or tariffs.
  - The BCAF should be completed prior to tariff development.
  - Utilities should publish short-, mid- and long-term marginal distribution capacity costs at the sub-nodal level.
  - Clean Coalition distinguishes two different methods for evaluating DER investments: deterministic approach and the option-value approach. Essentially, the deterministic approach assesses cost effectiveness by comparing the net present value of avoided costs to the program costs, which can undervalue DER investment because it does not accommodate alternative outcomes and low-probability but high-consequence reliability events. Alternatively, the option value approach recognizes variability in different components of the valuation analyzes the impact of co-variance amongst key components (such as how weather and demand co-vary and influence energy prices). This approach is being incorporated into the valuation methodology for demand response in the current California PUC DR proceeding instituted to update the methodologies used to value DR programs.
  - Clean Coalition recommends careful review of the applicable discount rate, leveraging the lowest cost of capital available on behalf of ratepayers, which may be realized through public bonds or financing.
  - Regardless of the adopted discount rate, the future costs to which the rate should be applied must include the risk and hedge value associated with the alternatives being compared, including the option value, as these represent real costs to the ratepayer.
  - The functions and services provided to the electric grid and the methods for establishing the value of these functions should be technology-agnostic and broadly applicable to any resource in relation to its performance and location.
  - Methods for determining distribution-level locational marginal value have already been developed, and products implementing these are commercial available.
  - While the White Plan appropriately recommends a methodology be developed to characterize DER resource profiles and determine to what degree those resources reduce energy, capacity or ancillary services needs, it is first essential to determine the local energy, capacity and service needs of the system.

- Values should be evaluated as synergistic portfolios rather than as individual facilities or technologies because complementary installations can greatly increase the range and reliability of functions.
- The California Distributed Resource Plan proceeding seeks to establish methodologies for utilities to plan for higher penetrations of DERs within the distribution grid and to identify optimal locations for their deployment (those which are cost-effective without requiring any grid upgrades). This requires both location-specific valuation and integration-capacity analysis ("ICA") maps. DER capacity of each line section, circuit and substation currently available with minimal upgrades is established through the DRPs, and these results can be utilized in evaluating DER portfolios and net ratepayer benefit opportunities.
- Adopted BCA methods should consider interconnection practices, which may be reviewed and amended as necessary to streamline the approval process and ensure predictable and reasonable costs.

- New York State Department of Environmental Conservation
  - DEC recommends that the Commission structure the BCAF so that it reflects state policy to reduce emissions from all energy sources as a whole.
  - DEC supports estimating the benefit of DER in terms of the damages from CO2 that could be avoided by reducing the load on the bulk power system.
  - The Commission should either apply a societal discount rate or design adders that represent a willingness by the State to pay now for assets that protect New Yorkers and that reduce avoidable costs from climate change and other environmental threats.
  - It is unclear how the use of costs, whether subtracted or added, will incentivize reductions in emissions by 2030.
  - It may be preferable to treat individual costs associated with GHG emissions separately rather than as a single value.

- Multiple Intervenors ("MI")
  - MI is interested in ensuring that the economic value of DER is reflected as accurately as possible.
  - BCAs should analyze both individual measures and projects as well as portfolios. A mere grouping of projects together in a portfolio that may be judged cost-effective as a whole should not be sufficient to justify non-essential projects that fail the analysis on their own.
  - In terms of full lifecycle analysis, it is exceedingly difficult to quantify and evaluation costs and benefits over a long period of time, resulting in undue reliance on inaccurate, long-term projections. Near-term projections should be weighted more heavily.
  - There is a need to do comparisons to a business-as-usual case and a range of alternative scenarios when projects are being evaluated.
  - Staff needs to describe how the various tests will be utilized, especially if and when they produce conflicting results.
  - Qualitative assessment should be the exception, not the rule, and the Commission should be reluctant to overrule results of a BCA absent truly compelling circumstances.
  - If the Commission is going to consider non-quantifiable benefits, it should consider non-quantifiable costs.
  - There are many missing cost components. For example, variable energy resources have low capacity factors, thereby increasing the State's IRM. "The White Paper does not include this potential cost, nor does it include the cost of the incremental, baseload

generation that would be needed to back up a large influx of intermittent renewable resources, some of which are considered DER."

- The Commission should refrain from attempting to quantify selected environmental externalities and incorporating them into the BCA. MI is concerned that neither the Commission nor any other party is capable of accurately quantifying environmental externalities in the short-term or long-term. The scientific evidence in this area is frequently changing, causing the values attributed to certain factors to be extremely volatile.
- It is important that the BCA be conducted in a neutral, without artificially benefiting DER investments over others.
- Attempts to include environmental externalities in the BCA will require the expenditure of substantial resources. MI is very concerned that the speculative quantification of environmental and other externalities in the BCA may lead to the approval of investments that, on a purely economic basis, are not cost-effective, thereby exacerbating the State's competitive disadvantage in terms of electric costs.
- The Staff White paper is proposing that only certain, selected externalities be quantified and incorporated into the BCAF, which is problematic. Doing so on a selective basis tips the scales too far in one direction.
- If the Commission incorporates environmental externalities into the BCAF and they are inaccurately high, it could lead to decisions that increase costs to customers and exacerbate the State's already-substantial, competitive disadvantage vis-à-vis other states with respect to energy costs.

- New York Battery and Energy Storage Consortium (NY-BEST)
  - The Staff provides no guidance on how the three tests relate to each other or how they will be weighted against each other in a utility's final screening analysis.
  - The BCAF and DSIPs should be coordinated with NYISO studies as well as others.
  - BCAF should include both sensitivity analyses for load growth and mechanisms to value flexibility and optionality.
  - Utility-specific handbooks should be updated annually, allowing for flexibility but within a clear set of standardized parameters.
  - The BCAF should more closely reflect the State's clean-energy goals and REV objectives.
  - NY-BEST recommends the addition of the following benefits: system efficiency, system optimization, fuel and resource diversity, customer/community engagement, grid flexibility, expansion of circuit hosting capacity, support of higher levels of renewable energy integration, optionality (modular scalability), maintenance of critical load, power islanding, local emergency power and allowing greater degrees of asset utilization.
  - Optionality should also be a value included to capture modular and easily scalable technologies and solutions.
  - A value associated with flexibility is missing from the BCAF.
  - Both optionality and flexibility reduce the risk of unrealized benefits and stranded assets and of additional costs to meet unanticipated needs and create high asset utilization by deploying proper-sized solutions at each required timeframe.
  - The reliability and resiliency categories are too limited in scope. The ability to maintain critical load is absent as is the ability to firm renewable resources and demand response.
  - Net avoided outage costs not only produce societal benefits but have an impact on utility costs in many ways, including through the utilities' performance requirements which are subject to punitive financial repercussions.

- The utilities need to continually enhance their modeling methodologies to allow for a more granular calculation of costs and benefits.
- NY-BEST urges the Commission to ensure that all of the information and data needed for DER providers to complete the BCA methodologies should be provided in the BCA Handbook to include the following" regional load projections, circuit hosting capacity, nature of solution sought (how long, what capacity, etc.), services required and land available at substation.

- Exelon Companies ("Exelon")
  - In order to advance the Commission's stated REV objectives, the BCA Framework must:
    - Recognize the existing levels of reliability and resiliency present in the current central station and grid framework and work to maintain and enhance those existing values;
    - Recognize that basing decisions on speculative or inflated benefits, or ignoring real costs and risks, simply diminishes the value of the BCA;
    - Fairly and accurately identify and quantify the marginal costs and benefits of DER compared to traditional utility investments and expenditures;
    - Not unduly favor short-term benefits over long-term benefits such as reliability and energy-cost stability;
    - Appropriately account for externalities (e.g., greenhouse gas) but exercise common sense, practical judgment and focus on externalities directly related to the energy and policy objectives of the REV process that are transparent, verifiable and quantifiable;
    - Initially focus on and prioritize decisions and investments for the distribution system affecting constrained circuits;
    - Recognize the significant costs, such as advanced automated metering, additional Internal Reserve Margin ("IRM") capacity requirements to accommodate increased intermittent resources, increased ancillary services at the NYISO level and distribution system upgrade requirements needed to develop the distribution-level operational control systems to accommodate the future levels of DER envisioned, and the on-going costs of performing those functions and updating BCA handbooks and processes; and
    - Work within, and not compromise, larger market structures. If the success of competitive markets is to continue, market-based investment and operating decisions must occur in parallel with regulated and partially-regulated decision making applying the BCA. The BCA should be structured to work with wholesale and capital markets, and avoid price signals that compromise those markets, investments in them, or the competitive prices on which they rely. In addition, there are reliability and economic risks when distribution dispatch signals are disconnected from wholesale dispatch signals. Managing these risks will require detailed coordination between DSPs and NYISO. The functioning of the DSP should align with the NYISO wholesale market model, and the costs and benefits of coordination should be reflected in the BCA tests.
  - Exelon notes that the following elements are necessary for the successful development and implementation of the BCAF:
    - The BCAF must be complementary and integrative of and linked to all REV proceedings (e.g., large-scale renewables, the MDPT, Track 2, New York State Clean Power Plan State Implementation Plan and the upcoming RGGI Initiative

2020 re-evaluation). The BCAF needs to function effectively in a broader content of state and regional markets and initiatives.

- The BCAF should be realistic, consistent and unbiased. The BCA is not about validated fore-ordained winners and losers. It is about determining what options are most efficient and most beneficial to customers and society, particularly where, for identified reasons, a purely competitive market solution is not the choice. If the BCA is unrealistic and biased, it cannot meet the goal. Accordingly, DER alternatives must be held to the same standards, including meeting the same delivery requirements, and evaluated on the same cost basis as the utility solution against which it is being measured. "In developing a fair comparison of DER, projects must stand on their own, net of government subsidies which mask the true cost of most renewables, and any BCA must account for and include risk premiums in calculations for potential non-performance or other failure of a DER alternative to traditional infrastructure investment." Projects should have to pass at least the SCT, or otherwise, the BCA is merely a justification for projects that are economically inefficient and cost society resources.
- The BCAF must be implemented workably. The first priority should be investments affecting constrained circuits. Continuing BCA analysis should reflect the diminishing marginal benefit that each succeeding project might offer and the diminishing marginal value of incremental units of "benefit." At some point, there will be saturation.
    - The BCA is not a static process but rather, changes as investments on the grid occur.
    - Different feeders may be affected differently by the same type and quantity of DER as well as the benefits being delivery (e.g., resiliency, reliability, public safety). Mitigation costs will also vary with location.
    - Secondary impacts on the bulk power system design and operation must be considered.
    - Distributed resources will affect the operation of the system at each stage, and the need for further real-time capabilities to operate complex systems with DER proliferation can also add to general T&D infrastructure costs driven by interconnection of a DER portfolio while an individual DER might not.
    - The BCA process will be complicated and dynamic and needs to be taken through an incremental and iterative process.
- Comments on Avoided Energy.
    - Forecasts, particularly price and demand/use forecasts, can have a major impact on the results of a BCA.
    - Ensuring the best and most consistent forecasts is important not just to promote accuracy but also to ensure that forecasts do not tilt the results to favor one outcome over the other. Resources that are dependent on a debatable assumption to pass a BCA are not as likely to be societally beneficial.
    - There should be no bias toward high-price or high-growth assumptions simply because those assumptions favor DER.
    - The process should be about getting the BCA right, not about validating arguable assumptions.
- Comments on Avoided Transmission and Distribution Costs

    - Customers can benefit from DER that provides real, added resiliency or reliability such as lowering the frequency or duration of outages. The quantification, and not just qualification, of these reliability and resiliency benefits should not be overlooked.
    - While Exelon generally agrees with the proposed net avoided outage cost methodology and that a net avoided restoration costs methodology that captures the speed and cost of restoration before and after a DER-based alternative should be factored into the BCA, the details must be carefully developed.
    - While BCA should not double-count costs that delivery resiliency and reliability benefits, it should only include costs that enable additional reliability and resiliency benefits attributable to DER. Conversely, while DER resiliency and reliability benefits would likely require infrastructure improvements to enable two-way power flow on the distribution system, such costs may already be included in incremental T&D (and DSIP) costs and to that extent, considered baseline investment.
    - The BCA recognizes the need for additional granularity beyond that typically used by utilities today. However, the data are becoming accessible to utilities but the BCA needs to recognize the practical implementation of the requirement.
    - Benefits attributable to lower cost ancillary services or reduced need for ancillary services from the wholesale market need to be substantiated.
- Comments on wholesale market price impacts
    - Alleged wholesale market price impacts attributable to any proposed utility investment or expenditure are not benefits that should be included in the BCA regardless of which BCA test is applied.
    - Claiming that an otherwise uneconomic project would suppress the competitive price of energy set by the market and then using that assumption as a justification for building the project and imposing its costs on customers is bad public policy and economically inefficient.
    - There are significant and inherent uncertainties in the assumption that market prices would be suppressed over time. Projects that are actually economic will pass the BCA test without inflating their assumed benefits and those that require that price suppression be an assumed benefit should not pass the test.
    - The risks and harms of including alleged price suppression as a benefit in the BCA are serious and the costs significant.
    - Alleged price suppression should not be counted as a benefit under the SCT because it represents no resource efficiency gain for society as a whole and would leave to economically inefficient resource decisions for society.
    - The SCT should be used because it is the most comprehensive, and when applied correctly, it considers the overall interests of all parties that support the competitive markets to customers' ultimate benefits. Any investment that fails to pass this test should not be approved.
- Externalities and GHG price

- Exelon advocates aligning REV with state, regional and federal GHG standards to guarantee that energy and environmental policies are consistent and complementary.
- While the BCA properly recognizes GHG externalities, it should not artificially create preferences of how to achieve GHG reductions.
- Valuing avoided emissions, especially GHG, is critical to accurate assessment of both DERs and other alternatives. New York should remain consistent in how it values GHG for both distribution and central station resources and, whatever method is used, it must be applied to all resources equally, otherwise it will distort price signals and harm the BCA process.

▪ Other comments
- Exelon agrees that the utility WACC should be used as the discount rate for evaluating projects.
- The cost of defending against cybersecurity risks, as well as the added risk itself, should be considered in the BCAF, particularly when evaluating DER.
- The Commission needs to "get it right," as errors will lead to wasted capital, increased costs and lost opportunities to deliver actual value.

- Institute for Policy Integrity (IPI")
  - IPI supports the use of the SCT, with a societal discount rate.
  - IPI differentiates between resource-allocation decisions and pricing decisions. IPI lists four categories of utility expenditures: 1) utility investments in the DSP platform; 2) procurements of DERs via selective processes; 3) procurements of DERs via tariffs; and 4) energy efficiency programs. #1, 2 and 4 involve resource allocation decisions and #3 involves pricing decisions.
  - In resource-constrained work, having benefits greater than costs is a necessary but not a sufficient condition for a project to be undertaken. Alternative scenarios must be clearly identified so that the net benefits of a project can be compared against the net benefits of alternatives.
  - The BCA should differentiate between resource-allocation and pricing decisions. Resource-allocation decisions are relatively straight-forward and described when compared to pricing decisions. The BCA is intended to calculate the total costs and benefits of a project; it is not intended to establish marginal costs and thus, it cannot be used to determine efficient price signals.
  - Clearer guidance is needed on how exactly the BCA would be used in pricing decisions, the distinction between values that would be used for monetization in a BCA and values that would be used in tariffs and the necessity of separate marginal cost studies is needed.
  - Staff should clearly state that a decision rule should be based on the net present value of benefits and costs rather than on a benefit-cost ratio. A ratio-based approach could mask scale differences, leading to misleading results.
  - The BCA needs "robustness checks" of results by conducting sensitivity analyses. The intensity of sensitivity analyses should depend on the uncertainty surrounding specific parameters, e.g., the costs associated with building solar PV are more certain that the impacts on the grid at varying penetration levels.

  - Staff should consider a variety of risk-mitigation analyses and methodologies include breakeven analysis and multi-criteria decision analysis (most particularly when one or more value components cannot be quantified).
  - Staff's recommendation of using modified versions of the value of avoided energy use and of avoided emission adds unnecessary complexity and creates a risk of distortions in the analysis.
  - The inclusion of compliance costs in the LBMP not unnecessarily complicates the calculations.
  - IPI states the following: "As Staff explains in the Track 2 White Paper, not only do the resource savings associated with DERs depend on the time and location of their deployment but the amount of external benefits also depends on the marginal generation being displaced at a particular time. Such granularity is especially important given the Commission's intention to use this benefit-cost framework as a basis for DER tariffs. Thus, Staff should incorporate its analysis of granularity from the Track 2 White Paper into the benefit-cost analysis framework, explaining that the analysis of both forecasted resource savings and the quantity of avoided emissions should consider the effects of time granularity.
  - Accurately valuing emission benefits is vital to ensure the efficient allocation of resources among different investment alternatives throughout the REV process, whether for DERs, DSIPs or tariff development.
  - "If the temporal dimensions are not taken into account, and all DERs are rewarded based on the same average quantity of avoided emissions, then the market incentives will lead to more investment in cheaper DERs, regardless of whether they are the most beneficial for the society when externalities are taken into account."

- Joint Utilities ("JU")
  - A fundamental principle is to level the playing field between DERs and traditional utility investment options.
  - There are many day-to-day utility functions for which BCA tests are not applicable.
  - The BCAF and BCA tests must be applied in a transparent manner not only by the utilities but also by NYSERDA, NYPA, LIPA/PSEG-LI and others.
  - The JUs have proposed a new test, the Distribution Cost Test, to be used as the primary screening test by utilities. The DCT is identical to the UCT (also called a Program Administrator Cost test or PAC) in all respects except that it does not directly include wholesale market costs and benefits since they are directly realized by participants.
  - Only potential portfolios of DERs that pass the DCT should be considered for procurement via selective processes.
  - The JUs support the continuance of the existing BCA for existing energy efficiency programs, provided that the cost-recovery provisions remain in place.
  - The quantification of benefits under BCA tests should not be a proxy for establishing payments to DER participants. Benefits quantified under BCA should not be presumed to be, or confused with, revenues a DER provider will receive.
  - The JUs will use competitive procurement techniques "where practicable to select resources in a cost-effective manner."
  - If monetizing costs that JUs do not avoid, the Commission should consider whether the impact on customer bills is warranted and if so, require full and timely cost recovery of such amounts from customers.
  - The JUs are not able to capture locational values.

- JUs are requesting that several principles should be revised or eliminated since they imply a bias for DERs over other alternatives and may result in higher customer costs.
- JUs note that in practice, a full lifecycle investment analysis is difficult when comparing long-lived utility investments with DER portfolios consisting of different types of assets with varied and shorter useful loves. Work is needed to develop a workable way to address the differences in asset lives.
- Great care must be taken so that the BCA avoids a bias toward any particular technology or type of solution.
- Care must also be taken not to fall into the trap of using judgment to “reverse engineer” desired results.
- The provision of a stable investment environment for DERs should not be a principle for the BCAF. As long as there is a level playing field for assessing utility solutions and DERs, and thus an economically efficient DER market, the Commission should be agnostic about the results rather than requiring a tilt in favor of a result.
- The development of a stable environment for DER depends on many factors that go beyond the question of whether DERs pass any appropriate benefit-cost test. Factors include level of market animation, market potential for DER deployment, actual DER performance, and impact of continued technological advances of both DERs and the operation of the grid.
- Artificially stabilizing the environment for DER through subsidies or other market distortions that insulate it from any inherent and economically fundamental risks and uncertainties is not an appropriate principle for the BCAF and may result in decisions that do not benefit customers.
- JUs support the need for a statewide transparent and consistent BCA approach. There needs to be an evaluation platform for all resources so that REV-related decisions are made in an objective and fact-based manner to benefit all New York energy consumers. (JU notes that NYSERDA proposes significant expenditures not supported by any BCA.)
- The BCAF should be supported by consistent inputs and assumptions so that targets set for REV metrics are based on robust and accurate data. Data would include information used to develop the BCA handbooks, results from applying the BCA tests and monitoring and verification activities used to update the handbooks.
- The handbooks should be filed with the DSIPs. Aligning them allows for a combined review, comment and approval process.
- The JUs list potentially acceptable cost and benefit line items, although not necessarily at a granular level (granularity is likely to increase over time). These include ones generally used in the proposed BCAF. They include lost utility revenue and shareholder incentives. The JUs also list a number of other BCA input categories that require further analysis on implementation costs and effectiveness and may or may not be justified for inclusion as part of further handbook filings.
- The JUs are recommending adopting National Grid’s screening process and four-part test to identify which infrastructure projects would be subject to specific BCA tests. Utility infrastructure projects that pass this four-part test would then be subject to an economic test using the DCT and suitable DER shapes and parameters to evaluate the anticipated cost-effectiveness of the traditional utility project against a proxy portfolio of non-wires alternatives.
- If a proxy portfolio is cost-effective on the basis of the DCT, then the utility would formally solicit DER alternatives from the market and apply the DCT when evaluating DER proposals against one another and against the traditional distribution system alternative. To the extent that multiple portfolios are cost-effective, the JUs propose to optimize and

ultimately select the third-party alternative(s) based on performance under the other three BCA tests.

- o BCA tests are appropriate tools only to compare solutions that offer equivalent functionality or optionality to the grid, that is, that can reasonably substitute for the specific traditional investments at those specific locations with no degradation of system or circuit performance, including power quality, reliability, safety and resilience.
- o BCA tests are not applicable to demonstration projects, research and development, promotional and outreach activities related to REV, customer portals, advanced metering infrastructure or equivalent, distribution automation and other grid modernization investments, technology platform investments, software and systems required to develop and implement DSP markets, and other DSIP supporting investments.
- o Introducing the additional externality value of GHG emissions into the BCAF will simply raise electricity costs to customers without any benefit of reducing emissions.
- o The JUs support the use of the utility weighted average cost of capital as the appropriate BCA discount rate. There needs to be clarification as to whether it is on a pre- or after-tax basis.

Appendix J: NECHPI Recommendations on Foundational Issues

Require the Development of Critical Foundational Energy Analyses and Standardized, Transparent Methodologies, Procedures, Processes and Documentation across all Utilities, including the BCAF.

The utilities are undergoing fundamental changes in their clean-energy missions, goals and objectives, and NECHPI understands the need to align with REV's vision and goals as well as to align with existing and new DER programs, internal to the utilities as well as with other organizations such as the Clean Energy Fund/NYSERDA and NYISO. NECHPI believes that a considerable amount of foundational work still needs to be undertaken if the State is to successfully implement REV, align all of the various proceedings, including the Large-scale Renewables Program, if the utilities are able to meet various State and REV clean-energy mandates, and if the State is to achieve its clean-energy goals. This foundational work will also need to be done if a Cost-Benefit Analysis Framework is to be implemented successfully. There need to be baselines established in order for metrics to be selected and used to measure success of various programs, projects and other initiatives, and that can only be done if the State has undertaken the necessary "conditions-precedent" analyses.

The State has defined certain clean-energy goals to include the following: 1) reduce overall carbon emissions by 40%; 2) achieve 50% renewables of total energy supply; and 3) realize a 600 trillion Btu increase in Statewide energy efficiency. NECHPI believes that, until all programs and initiatives are integrated through a robust, detailed and vetted Cost-Benefit Analysis Framework and adhere to agreed-upon methodologies, process, procedures and metrics for valuing their net benefits, the State will not meet its stated goals.

To achieve these goals, along with the myriad of other related State clean-energy goals and REV objectives, will require hard work, dedication and commitment by all stakeholders. Time is of the essence. Given the amount of time is takes to develop and implement new programs, initiatives and tariffs, the Commission must ensure that the roadmap established through various proceedings is clear, provides a solid framework for putting in place all of the inter-related components needed to support success, and does so in a manner that maintains grid reliability, safety and affordability. NECHPI believes that many foundational elements are necessary in order for the process to be initiated and rolled out successfully and that these need to be undertaken as soon as possible.

The State has no detailed state integrated energy resource plan, which should be integrated with and form the basis for utility-specific integrated energy resource plans. Without these in place, there are no baselines established upon which to build out a distributed-resource plan for each utility that is scalable, measurable, and verifiable by distributed resource. California has a 10-year integrated energy resource plan that is updated biennially, and the utility-specific resource plans are fully integrated into the state plan, now down to the circuit level based on Commission mandates and reflected in utility Distributed Resource Plans filed on July 1, 2015.

California also has in place a mandated preferred-resource loading order, which specifies that utilities must first consider Energy Efficiency, Demand Response, and Distributed Generation (both renewables and CHP) before making traditional grid investments. (While not technically a part of the loading order, the utilities have included EV charging as a distributed asset in their Distributed Resource Plans.) Adopting a loading order provides a framework that ensures that utilities undertake technology-neutral analyses that are solutions-driven and support DER scale-up from the circuit level, the point of interconnection to the utility's distribution system.

The reading of the utility comments in these proceedings leads NECHPI to believe that New York will need a comparable preferred-resource loading order since it appears that the utilities are highly resistant to putting in place from ground-up processes and procedures which would allow the bona fide net-benefit analysis of DERs as potential replacements of traditional investments.

California has also mandated certain common methodologies and tool sets to which all utilities are required to adhere. NECHPI observes again and again throughout these proceedings the resistance of utilities to adopt common methodologies, processes, procedures and documentation, and given the sheer magnitude of the complexity of these proceedings, NECHPI believes that, ironically, their common adoption would provide multiple benefits to utilities, not the least of which is a rationalization of the foundational underpinnings to a new grid-planning approach common for all utilities.

- The following is a summary of NECHPI's recommended Commission mandates:

    - A biennial Integrated Energy Resource Report, which projects the consumption and generation of all energy resources in the state over a 10-year planning cycle, updated every two years, to be used by utilities to develop their integrated energy resource plans on a system-wide basis as well as down to the circuit level;

    - Detailed state resource plans by type of DER, including energy efficiency, demand response, solar PV, energy storage and CHP (based on the state's preferred-resources loading order). The plans also include EV resources given the state's specific resource targets for EV.

    - A locational net benefit methodology ("LNBM") consistent across all utilities. The California Public Service Commission has mandated the use of based of a tool from Energy and Environmental Economics (E3), the Distributed Energy Resource Avoided Cost (DERAC) calculator, as a starting point to identify the benefits that the utilities need to take into account in their LNBM analyses; the utilities have modified the tool to replace DERAC's system level values with location-specific values, wherever appropriate, and to add some locational values not covered in the DERAC tool. These additional adjustments are necessary to account for how much the specific DER meets localized grid needs, including the temporal and geographic coincidence of the DER attributes with the identified grid need, the dependability or predictability of the DER capacity, and the persistence of DERs within the required deferral period. These adjustments are relevant to estimating such items as transmission and distribution ("T&D") deferral benefits and are likely needed to be made by adjusting estimates of the various cost and avoided cost components of the all relevant circuit locations on the distribution system when evaluating specific DER alternatives.

    - A Commission-specified methodology that quantifies the capability of distribution circuits to integrate DERs within thermal ratings, protection system limits and power quality and safety standards of existing equipment. These limitation categories should already be common and agreed to among the IOUs, though parameters within each limitation might differ slightly among the IOUs due to IOU-specific design criteria or available data.

    - Common utility use of power-system modeling software to perform a dynamic analysis on distribution circuits within each utility's service territory. (In California, Cooper Power Systems' CYME Distribution Analysis and Scripting Tool with Python modules was used to implement the

Commission-mandated Integrate Capacity (Hosting) Analysis ("ICA") methodology and to perform an analysis that uses dynamic modeling methods and circuit performance data.)

- o Given what will be the dramatically increased importance of forecasting both supply and loads dynamically, the Commission might consider recommending common tools to ensure that there is a common framework for evaluating the assumptions behind utility forecasting projections.

- o Finally and perhaps most importantly, NECHPI would also like the Commission to mandate that all key REV entities which will need to be engaged in cost-benefit analyses (e.g., NYSERDA/CEF, the utilities and others) be required to adopt the same, agreed-upon, standardized methodologies such as the one represented by EPRI's Integrated Grid Benefit Cost Analysis Framework ("BCAF"), among others. In order to meet REV objectives, there need to be state, utility and circuit-level baselines established in order for metrics to be selected and used to measure success of various REV programs, projects and other initiatives, and that can only be done if the State has undertaken the necessary "conditions-precedent" analyses.

- o The Commission should consider mandating circuit-level maps of utility service territories, updated on a monthly basis, which will be able to provide locational and temporal values to the DER community once an EPRI-type Integrated Grid BCA is completed as has occurred in California. New York State should learn from California's experiences in developing and implementing BCAFs and utility distributed-resource plans.

- NECHPI recommends that the Commission consider initiating a collaborative process for developing a framework for integrating the various proceedings to ensure that any overlaps, inconsistencies and even contradictory elements are removed and that utility, DER developer and other stakeholder efforts are not duplicated unnecessarily. In addition, NECHPI believes that the working group can set the stage for the full integration and deployment of distributed energy resources that provide optimal customer and system benefits while enables the State to achieve its climate and other objectives.

Mandate across All Utilities the Use of EPRI's Integrated Grid Cost-Benefit Analysis Framework[45] as the Engineering and Economic Foundation upon which to Base an Accurate View of the Physical and Economic Requirements for Grid DER Integration from the Circuit Level through the Distribution, Transmission and Bulk Power Systems, to Accommodate Different Stakeholder Perspectives and to Provide Common Inputs for DER Cost-Effectiveness Screening Tests.

EPRI's Integrated Grid Cost-Benefit Analysis Framework, grounded in the fundamentals of power system engineering and economic analysis (See Appendix C for detailed description), recognizes and describes how to extend the results of circuit DER hosting capacity studies conducted at the distribution level through to the transmission level and the bulk power system. This approach recognizes the interdependent nature of DER impacts on system generation planning criteria (resource adequacy), operational criteria (such as the provision of operating reserves), and transmission system design and operations.

Thus, because DER influence emanates from where the resource is interconnected, EPRI maintains that a bottom-up approach is required to identify the specific locational impacts and then trace their consequences through the distribution, transmission and bulk power systems without double-counting or missing key elements. EPRI's framework emphasizes the inextricable ties between the distribution,

[45] *The Integrated Grid Benefit-Cost Analysis Framework*, Electric Power Research Institute, February 2015

transmission and bulk power systems that are needed to study and characterize DER integration which, in turn, provides a framework for assessing DER impacts and their benefit and cost consequences and captures their potentially cascading and collateral impacts.

Another critical point is the need for integrated distribution and transmission planning and operations as DER penetration levels increase. Increasing DER levels will drive the need for integrated T&D models and for the exchange of information that can be used to simulate and evaluate the aggregate system reliability, affordability, sustainability and safety implications of various system-development, investments and technology choices.

NECHPI believes that EPRI's CBA framework, coupled with the use of the California utility Distributed Resource Plans as roadmaps (based on the EPRI model), provide a standardized and transparent bottoms-up approach to all of the elements required for robust, systematic, integrated distributed-resource planning. The advantages are numerous:

- **EPRI thus seeks a common ground for a CBAF for all stakeholders. The framework is meant to be the same regardless of the electric system, state and local policy goals, utility business practices, and regulatory oversight parameters and whose outputs can be used in any cost-effectiveness screening processes.** EPRI maintains that "the benefit-cost framework for the Integrated Grid establishes this sound engineering and economic foundation; from it, multiple stakeholder perspectives can be examined upon it." Critical to using new analytic tools for DER assessment is an understanding of the perspectives of all parties involved and that, while reconciling these different perspectives may be difficult, the chances of success are improved if all can share an accurate understanding of the physical and economic requirements for grid integration.

- The approach establishes real, engineering- and economic-driven values to the circuit level, and traces all of their causes and effects through the distribution, transmission and bulk-power systems to remove double-counting and to provide the ability to update values dynamically as the DERs scale on and across circuits and substations through the distribution system. The approach also has the advantage of providing a structure for actual measurements of performance by technology or combinations of technologies as well as of GHG and other criteria-pollutant emissions. See Appendix H for a discussion of recent breakthroughs in the integration at the circuit level of real-time emissions and grid data analysis that is able to turn price-responsive assets into emissions-responsive assets.

- If the distribution planning process starts with baselines down to the circuit level and builds out from there, this approach changes the whole conversation around the CBAF and the numerous issues pointed out in various active-party comments.

- EPRI's BCAF provides the concrete basis for the implementation of the REV market-driven vision based on locational and temporal values down to the circuit level. NECHPI argues that the proposed, fairly traditional approach to the proposed BCAF entails numerous compromises because of the attempt to adopt "gross," system-wide values which can never be used to establish circuit-level locational and temporal net benefits, which as EPRI notes repeatedly, vary widely among and between circuits (even along line segments of circuits).

- It alleviates concerns in cost-effectiveness tests about the complete symmetry of costs and benefits since all values associated with them are established from the ground up.

- It allows for transparent and standardized comparisons of DER solutions with traditional utility investments for solving specific grid issues locally and across the distribution system and enables utilities, the Commission and stakeholders to peel the "financial onion" down to all of its component parts. This will allow the alignment of existing utility capital-expenditure programs (including grid modernization and storm hardening) funded under current general rate cases (particularly expenditures that need to be made regardless of DER integration and scale-up), to be separated from existing, new and proposed DER programs and grid expenditure programs (proposed and existing) which enable the scale-up of DERs on the distribution system.

- The approach allows for the streamlining and full integration of DER interconnection processes into a utility's distribution-planning processes. By having detailed knowledge of each circuit, the utility can enable more efficient and cost-effective interconnections across the grid. (It should also be noted that it can identify those circuits where DER interconnection is uneconomic because the costs to "enable" DER interconnections are higher than the benefits DERs would provide. Again, this is advantage of the bottoms-up approach in being able to analyze, assess and prioritize circuits for DER integration.)

- It provides the framework for integrating with transmission and NYISO long-term planning functions, which will include an analysis of the effects of grid-tied DERs, most particularly large-scale renewables, as well as behind-the-meter resources, on the transmission and bulk-power systems.

- The outputs of the EPRI BCA provide common inputs to the various tests to be used in screening utility DER programs and programs for cost-effectiveness. While EPRI, in its primary analytic framework, only includes those costs that can be recovered through its revenue requirements, its "accommodation" methodology allows for the incorporation of costs and benefits not priced by the market or administratively (and therefore, not included in a utility's revenue requirements.) EPRI's view is that the utility's perspective is still essential because DER accommodation will require the utilities to incur costs to realize benefits.

Integrate all REV programs and initiatives, utility distribution and transmission planning functions, their ETIPs and DSIPs, DR programs, demonstration programs, microgrid projects under the NY Prize, other existing and proposed tariffs and programs and general rate cases as well as NYISO planning processes.

In New York State, there is a host of recent proceedings as well as on-going DER programs and tariffs, some of which are being taken over by the utilities, all of which have direct relevance to each utility's internal distribution and transmission planning processes as well as the implementation of the LSR Program, the CEF and other state DER-related programs and initiatives, many of which overlap with or are transitioning to utility-managed programs. NECHPI believes that a key to the success of meeting state clean-energy goals and REV objectives will depend on how well they are integrated into utility distribution planning as well as transmission and bulk-power planning processes. All of the state's, NYISO's and utility DER and LSR programs, initiatives and tariffs should begin to be aligned to maximize the state's and REV's clean-energy objectives.

However, NECHPI observes that there is currently a lack of transparency on how these multiple proceedings and existing programs and tariffs will be aligned, the possibly overlapping costs associated with implementing them and the manner by which they will be integrated into the utilities' next rate cases. There is considerable concern on the part of active parties regarding the lack of transparency on budgets and proposed expenditures on all of the components supporting the scale-up of DERs and VERs.

The preferable course of action in NECHPI's estimation is to have the Commission provide guidance to align and integrate all of REV's various proceedings, DER programs and tariffs into the DSIP process and the next general rate cases while maintaining the integrity of various Commission proceedings with already established procedures and active parties with expertise. Given the importance of adhering to fundamental rate-design principles, most particularly those of equity, affordability and cost causation, it is critically important that active parties are able to assess each program's economic and financial viability in the context of all of the other fundamentally related programs and initiatives to prevent duplication of effort, conflicting priorities and duplicative economic investments.

NECHPI recommends that the Commission consider initiating a collaborative process for developing a framework for integrating the various proceedings to ensure that any overlaps, inconsistencies and even contradictory elements are removed and that utility, DER developer and other stakeholder efforts are not duplicated unnecessarily. In addition, NECHPI believes that the working group can set the stage for the full integration and deployment of distributed energy resources that provide optimal customer and system benefits while enables the State to achieve its climate and other objectives.

From its observations on the proceedings so far, NECHPI notes that in order to move utilities toward a fuller integration of DERs into distribution system planning, operations and investment and to enable the development and implementation of the DSP platform, all of the currently separate proceedings need to integrated to remove duplicative efforts and possibly conflicting financial investments and to establish an end-to-end framework that includes the identification of tariffs, contracts and other compensation mechanisms for deployment of cost-effective DERs, which will be the focus of the Track II proceedings. It is clear from the comments in the current BCAF proceeding that active parties are very concerned about how and through what means the CBAF will apply (or will be able to be applied) to the development of new tariffs. These issues should be addressed carefully and explicitly in an open, transparent collaborative forum.

Initiate a Collaborative Stakeholder Process As Soon As Possible to Align Utility Distribution, Transmission and NYISO Planning for the Scale-Up of DERs, including Large-Scale Renewables.

Closer coordination between the PSC, utilities and NYISO, particularly in regard to planning processes, will also become increasingly important. NECHPI members participate actively on NYISO Business and Market Issues committees and observe that NYISO's rules and regulations governing behind-the-meter ("BTM") resources are complex, expensive and generally onerous to participate in wholesale markets, particularly when compared with other ISOs such as PJM and CAISO. The NYISO is currently developing a new behind-the-meter tariff to allow participation in its energy and capacity markets, but the requirements are restrictive, and it is estimated that a relatively circumscribed number of MWs will be eligible for participation. NECHPI believes that opening up wholesale markets for BTM-resources participation will be a key component to enable the success of REV.

NECHPI would also note that many DER developers of both behind-the-meter and in-front-of-the-meter variable energy resources are counting on their ability to participate in wholesale markets in order to improve revenue streams and therefore, project economic viability. At present, much of the REV discussion surrounds monetizing the services to be provided by distributed resources and large-scale renewables. However, it will require far greater levels of communication, coordination and integration between the Commission, utilities and NYISO to open up wholesale markets to DERs and LSRs. In addition, grid-connected LSRs at high penetration levels can have substantial price-suppressive effects on wholesale markets, which must be factored in to any program design being considered by the Commission.

It would appear from various filings in the REV proceedings as well as a number of meetings and conference calls that both the utilities and NYISO believe that they have five years before serious, integrated distribution and transmission planning for the new 21st century grid of rapidly increasing penetration levels of DERs and large-scale renewables will be needed. NECHPI has heard from various parties that there is a belief that the State will not achieve DER penetration levels that would warrant the level of planning undertaken by utilities in California and Hawaii, as an example. NECHPI begs to disagree.

To begin with, even California, which has had proactive renewable-energy policies for over a decade, has been faced with what is popularly called the “duck curve,” and is now playing catch-up to ensure that distributed resources are effectively integrated into its traditional distribution-planning approaches. As a result, the recently filed California Utility Distributed Resource Plans (“DRPs”) on July 1, 2015 are case studies on what is needed to undertake “true” integrated distributed resource planning from the bottoms-up.” The plans take a technology-neutral, portfolio-driven approach to the scale-up of distributed-energy resources.

There has been significant discussion in New York State as well as elsewhere in the U.S. and internationally about the requirement for considerably closer alignment between distribution and transmission planning functions within utilities and between distribution and bulk-power-system planning and integration as the penetration levels of variable energy resources increase. NECHPI sees no guidance on these issues in the REV proceedings. This is a major oversight and needs to be addressed. NECHPI is active on various levels in both the wholesale and retail markets and is concerned about the slowness of progress to develop processes, procedures, rules and regulations regarding the large impacts DERs and VERs will have on the bulk power system as well as on transmission requirements.

NECHPI recaps NYISO’s comments on the Large-Scale Renewables Program White Paper since NECHPI believes they are important in the context of the BCAF, most particularly the issues surrounding the price-suppression and other possible negative effects of the scale-up of renewables on wholesale markets and whether those effects should be deemed a benefit. NYISO’s observations, coupled with the analyses provided by NECHPI in Appendix F on the effects of variable energy resources on wholesale markets, would indicate that the issue is serious enough to warrant a collaborative working group to discuss the many issues surrounding the scale-up of distributed energy resources, including large-scale renewables and their effects on wholesale markets.

The following is a summary of NYISO’s comments:

- The options provide in the LSR White Paper raise concerns regarding their compatibility with wholesale markets.
- State policies need to be consistent with wholesale market policies.
- The options provided do not represent a platform for transitioning to a purely market-based approach.
- NYISO’s independent market evaluator, Potomac Economics, is quoted as saying that the risk is primarily allocated to customers; the inherent price is not reduced, just shifted to customers.
- There is a real danger of negative pricing.
- There are fixed-price guarantees regardless of market outcomes or performance. The price-suppressive effects of LSRs also reduce incentives to invest in high-value locations.
- The proposal will exacerbate issues of excess generation in upstate New York.

- NYISO provides strong arguments for maintaining a REC-only approach.

NECHPI agrees with NYISO that there are likely to be negative effects (most particularly price-suppression effects) on wholesale markets from the scale-up of large-scale renewables installations. This issue is not addressed and needs to be rigorously analyzed to ensure that existing competitive markets are maintained. Appendix D reviews recent literature which points to the limits of an “all-renewables” decarbonization approach for the foreseeable future. NECHPI is a firm believer that the ultimate decarbonization solution represents a mix of complementary distributed technologies that work together to provide a low-cost, efficient solution to achieving the State’s goals.