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Impacts of Demand-Side Resources on Electric Transmission Planning

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OAK RIDGE NATIONAL LABORATORY
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Electrical and Electronic Systems Research Division

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ACRONYMS AND ABBREVIATIONS

ARRA	American Recovery and Reinvestment Act (2009)
BA	balancing authority
BAU	business as usual
CREZ	Competitive Renewable Energy Zone (ERCOT)
DG	distributed generation
DOE	US Department of Energy
DR	demand response
DSM	demand-side management
EE	energy efficiency
EI	Eastern Interconnection
EIPC	Eastern Interconnection Planning Collaborative
ERCOT	Electric Reliability Council of Texas
LBNL	Lawrence Berkeley National Laboratory
LCOE	levelized cost of energy
LTPT	Long-Term Planning Tool (WECC)
LTSA	long-term system assessment (ERCOT)
NEEM	North American Electricity and Environment Model
NERC	North American Electric Reliability Corporation
PV	Photovoltaic
RPS	renewable portfolio standard
SAE	statistically adjusted end use (model)
SPSC	State-Provincial Steering Committee
SSC	stakeholder steering committee
T&D	transmission and distribution
TEPPC	Transmission Expansion Planning and Policy Committee
WECC	Western Energy Coordinating Council

ABSTRACT

Will demand resources such as energy efficiency (EE), demand response (DR), and distributed generation (DG) have an impact on electricity transmission requirements? Five drivers for transmission expansion are discussed: interconnection, reliability, economics, replacement, and policy. With that background, we review the results of a set of transmission studies that were conducted between 2010 and 2013 by electricity regulators, industry representatives, and other stakeholders in the three physical interconnections within the United States. These broad-based studies were funded by the US Department of Energy and included scenarios of reduced load growth due to EE, DR, and DG. While the studies were independent and used different modeling tools and interconnect-specific assumptions, all provided valuable results and insights. However, some caveats exist. Demand resources were evaluated in conjunction with other factors, and limitations on transmission additions between scenarios made understanding the role of demand resources difficult. One study, the western study, included analyses over both 10- and 20-year planning horizons; the 10-year analysis did not show near-term reductions in transmission, but the 20-year indicated fewer transmission additions, yielding a 36% capital cost reduction. In the eastern study the reductions in demand largely led to reductions in local generation capacity and an increased opportunity for low-cost and renewable generation to export to other regions. The Texas study evaluated generation changes due to demand, and is in the process of examining demand resource impacts on transmission.

1. INTRODUCTION

1.1 DEMAND RESOURCE EFFECTS ON TRANSMISSION

The first installment of the Quadrennial Energy Review is focusing on the country's transmission, storage, and distribution infrastructure. A question arises on whether demand resources such as energy efficiency (EE), demand response (DR), and distributed generation (DG) could have an impact on electrical transmission requirements. At a conceptual level it is expected that reduced demand, especially during peak periods, should lower the need for transmission services. For example, the reduction in demand growth since 2008 has led to the cancellation of several major transmission projects, such as PJM's Mid-Atlantic Power Pathway and Potomac-Appalachian Transmission Highline. This indicates a relationship between demand growth and transmission capacity growth, although other factors can blur or confound that conclusion.

In his 2004 paper for the US Department of Energy (DOE) and the Edison Electric Institute, Eric Hirst identified the following four broad reasons for construction of new transmission capacity (Hirst 2004).

- Interconnection of new load or generation: Facilities required to connect to the transmission grid but not necessarily to transport power across the grid.
- Reliability: Facilities required to meet standards such as those of the North American Electric Reliability Corporation (NERC) and regional reliability councils, but primarily the *NERC Planning Standards* (1997).
- Economics: Facilities that lower the cost of electricity production by reducing losses and congestion to permit greater use of low-cost generators to serve distant load centers.
- Replacement: Facilities that replace old, worn-out, and/or obsolete equipment.

The frequently updated *NERC Planning Standards* continue to be drivers for capacity expansion. In addition, a fifth reason has become more prevalent.

- Policy: Facilities required to interconnect resources to load to meet societal policies such as renewable portfolio standards (RPSs), reduced emissions, esthetics, improved grid resilience, or other policy goals.

Demand resources can affect transmission capacity needs in all of the following categories.

Interconnection: If demand is lowered or DG increased at the end-user location, then generally less interconnection of new load or generation may be needed. However, connections to provide backup or voltage support may still be required. These will largely occur on the distribution system rather than transmission.

Reliability: Generation planning reserves are a function of the expected peak demand so demand resources that shift or reduce load at system peak may lower the need for planning reserves and thereby interconnections. On an operational basis, the system must maintain operating reserves based on demands in real time (as well as to meet contingencies). EE will lower demands over most hours, while DR can target periods when the system is most congested, due to lack of either generation capacity or transmission capacity. These can cause direct reductions on the need for new transmission and distribution (T&D) resources or operational stresses on the existing system.

Economics: Demand resources can compete with supply both indirectly as customers invest in EE and directly as DR bids into the wholesale markets in several regions of the United States. Many types of DG are economic (e.g., combined heat and power, industrial cogeneration), and additional technologies are coming closer to economic parity (e.g., solar photovoltaic.) Their deployment near loads can reduce the capital cost of transmission as well the transmission losses from bringing power from more distant plants.

Replacement: By reducing demand, EE and DR may delay or reduce the size of replacement capacity when equipment becomes worn-out. However, this effect may be limited depending on how local power companies size their replacements. DG may similarly reduce the need, but since it can feed power back into the grid upgrades to the local distribution system may be required. DR and DG also require enhanced communication capabilities (i.e., smart grid) for them to be used to full effect. This may lead to required modifications of some equipment and/or earlier replacement.

Policy: Demand resources are some of the most environmentally benign sources available, due not only to the avoided emissions from generation but also to the avoided land and water impacts from generation and transmission capacity. Many portfolio standards and other policies recognize their benefits in the establishment and calculation of standards. Demand resources may lessen local T&D requirements and allow smaller or underground lines to become more feasible. These may also be desired for esthetic reasons or improved resilience.

A factor to consider is that while demand resources can lessen T&D requirements locally, reducing demand in regions that have either a low-cost or environmentally desirable source of generation effectively increase the supply of generation available for export. This in turn can increase the demand for transmission capacity (or perhaps just increased use of existing resources) to carry that generation to more distant loads. An example is the sharing of generation resources between summer and winter peaking regions, where demand is naturally lower in one region during one season allowing power to be exported to the other. Simulations such as the western study indicate this could occur in limited situations. If so, the result would still be a net economic benefit to the system.

1.2 DOE INTERCONNECTION TRANSMISSION STUDIES

In 2009, as part of the American Recovery and Reinvestment Act (ARRA), DOE released funds for transmission studies to be conducted for each of the three major physical interconnections in the United States. The objective was "to facilitate the development or strengthening of capabilities in each of the three interconnections serving the lower 48 states of the United States, to prepare analyses of transmission requirements under a broad range of alternative futures, and to develop long-term interconnection-wide transmission expansion plans" (DOE 2009). The Western Energy Coordinating Council (WECC) led the western study, the Eastern Interconnection Planning Collaborative (EIPC) led the eastern study, and the Electric Reliability Council of Texas (ERCOT) led the Texas study. The studies evaluated a variety of potential futures that could impact the possible transmission systems for each region. Each group developed their methods, collaborators, steering councils, software tools, assumptions, and scopes separately. The studies were initially completed in 2012, with additional studies continuing through 2014.

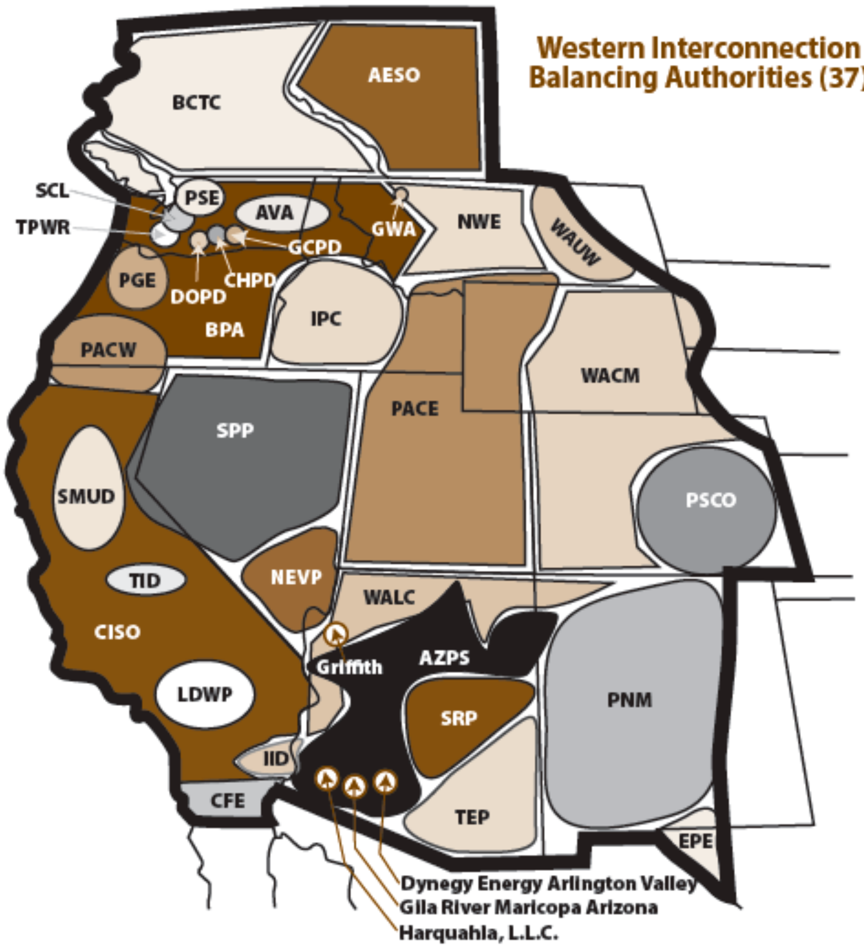
1.3 SCOPE AND PURPOSE

This white paper evaluates the results from these three regional studies as to the effect of demand resources on the transmission systems that were modeled. Most of the study cases evaluated within the three regional studies did not include changes in demand resources and so provide little information. Others included demand resources but also included other influences such as carbon pricing or RPSs, so it is difficult to establish the effect of demand changes alone. However, there were some scenarios or sensitivities that looked only at the effect of demand changes (either policy driven or by assumptions.) The combination of cases provided allows some insights to be gleaned about the relationship of demand resources and transmission.

2. DEMAND RESOURCES IN WESTERN TRANSMISSION STUDIES

WECC conducts transmission planning studies through its Transmission Expansion Planning and Policy Committee (TEPPC). In recent years, WECC's transmission planning process has been substantially expanded and enhanced with funding from DOE provided under ARRA. This expanded effort, designated the "Regional Transmission Expansion Planning" project, has entailed the development of biennial 10- and 20-year transmission plans that serve to identify future transmission expansion needs and options for meeting those needs. The analysis conducted for each plan evaluates numerous stakeholder-driven "study cases" (i.e., scenarios) using production cost modeling and capacity expansion modeling tools. State regulators and energy agencies have provided input to WECC's transmission planning analyses via (among other channels) the State-Provincial Steering Committee (SPSC), an entity formed by the Western Governors' Association and the Western Interstate Energy Board, which participate in the annual study request process.

Lawrence Berkeley National Laboratory (LBNL) and its contractors provided technical assistance to the SPSC and WECC in the development of energy efficiency-related assumptions and modeling inputs for WECC's transmission planning analyses in the 2011 and 2012 TEPPC study cycles. To implement SPSC study requests for both the 10-year and 20-year plans, two categories of scenario were developed: (a) reference cases that incorporate the expected impacts of current DSM-/DR-/DG-related policies and plans and (b) "high DSM/DR/DG" study cases that entail higher levels of demand-side policies, programs, and impacts than anticipated in the reference case.[1] For each study case, model inputs were developed for each of the 39 load zones used within WECC's modeling tools; these load zones correspond roughly to the set of balancing authorities (BAs) shown in Fig. 1.



AESO—Alberta Electric System Operator
AVA—Avista Corporation
AZPS—Arizona Public Service Company
BCTC—British Columbia Transmission Corporation
BPA—Bonneville Power Administration
CFE—Comisión Federal de Electricidad
CHPD—PUD No. 1 of Chelan County
CISO—California Independent System Operator
DOPD—PUD No. 1 of Douglas County
Dynegy Energy Arlington Valley[a]
EPE—El Paso Electric Company
GCPD—PUD No. 2 of Grant County
Gila River Maricopa Arizona[a]
Griffith—Griffith Energy, LLC[a]
GWA—NaturEner Power Watch[a]
Harquahla, LLC[a]
IID—Imperial Irrigation District
IPC—Idaho Power Company
LDWP—Los Angeles Department of Water and Power
NEVP—Nevada Power Company
NWE—NorthWestern Energy
PACE—PacifiCorp–East
PACW—PacifiCorp–West
PGE—Portland General Electric Company
PNM—Public Service Company of New Mexico
PSCO—Public Service Company of Colorado
PSE—Puget Sound Energy
SCL—Seattle City Light
SMUD—Sacramento Municipal Utility District
SPP—Sierra Pacific Power Company
SRP—Salt River Project
TEP—Tucson Electric Power Company
TID—Turlock Irrigation District
TPWR—Tacoma Power
WACM—Western Area Power Administration, Colorado-Missouri Region
WALC—Western Area Power Administration, Lower Colorado Region
WAUW—Western Area Power Administration, Upper Great Plains West

[a]Generation only; controls no load

[1] This activity occurred under the auspices of SPSC "work groups," with group participants—including state regulatory and energy agency staff, utilities, and regional DSM/DR/DG experts—vetting and providing input on key assumptions and methods. Critical review and input were also provided by the TEPPC DSM Task Force, the TEPPC Data Work Group, and other key participant groups within the TEPPC process.

Fig. 1. WECC balancing authorities (circa 2011). *Source: WECC.*

The overall 10- and 20-year WECC studies used different modeling methods. The 10-year study used production cost modeling, which simulates the operation of the power system—specifically, an optimal security-constrained economic dispatch—given loads and generation and transmission capacities. The model outputs were applied to analyze the effects of demand-side policies on transmission using congestion or utilization metrics, which indicate how heavily transmission lines are being used. By contrast, the 20-year study used a new capacity expansion model developed by WECC, the "Long-Term Planning Tool" (LTPT), which computes optimal (least-cost) generation and transmission additions required to meet load subject to economic, policy, and reliability goals and constraints. Thus, in the 20-year study, effects on transmission from demand-side measures (along with those of all other drivers) were reflected in actual new infrastructure investments. [2]

2.1 10-YEAR ANALYSIS

2.1.1 Scenario inputs

For the WECC 10-year planning horizon, the reference case was also known as the WECC "Common Case." To develop this case, load forecasts were developed by starting with the load forecasts submitted to WECC by the BAs for the 2011 planning cycle. These forecasts were then assessed to determine the extent to which they already captured expected impacts for existing EE policies and program plans over the forecast period. To the extent that they did not, individual BA-level forecasts were adjusted to take account of these impacts, in two categories: Ratepayer-funded efficiency programs, and federal minimum EE standards (Barbose et al. 2014a–b). A separate analysis was conducted to take account of DR impacts (Satchwell et al. 2013).

For EE, the 10-year High DSM scenario was developed based on the criterion of all cost-effective efficiency being implemented—that is, the "economic potential" (Barbose et al. 2014a-b). This was assessed on the basis of potential studies, utility information, and other sources. For DR, the 10-year scenario was based on an update to the Federal Energy Regulatory Commission 2009 assessments of DR potential (FERC 2009, Satchwell et al. 2013).

2.1.2 Energy and Transmission Implications

These EE and DR scenario inputs resulted in an 8.9% reduction in coincident peak demand and a 9.3% reduction in energy in 2022 relative to the Common Case (WECC 2013a). The energy reductions by BA are shown in Fig. 2, which highlights the variation across WECC.

The quantitative methods used for the WECC 10-year analysis did not include capacity expansion modeling. Thus, the analysis focused on transmission infrastructure already in place or planned for installation during the forecast period, and the potential effects of various policies and other factors, including demand-side measures on transmission, were estimated by analyzing changes in transmission path utilization or congestion that would imply a need for decreased or increased transmission capacity.

One possibility for potential benefits of aggressive demand-side load reductions is that they could result in a reduced need for new transmission resources. One reason this might occur is that demand-side

[2] Production cost models simulate operation of the grid with a fixed set of resources (generation, transmission, etc.), while a capacity expansion model operates over multiple years and can add or retire resources to meet the objectives of the simulation (e.g., minimize cost).

induced load reduction could decrease the level of new transmission needed to access renewable resources across long distances in order to comply with state RPS requirements. This could occur because these standards are defined in terms of a percentage of electricity consumption (or supply) that must be provided by renewable sources. Thus, if RPS compliance entailed long-distance transmission, then load reductions, by reducing overall supply requirements, could in turn counteract this by instead reducing transmission requirements, simply because they would lower the absolute amount of required renewable energy.

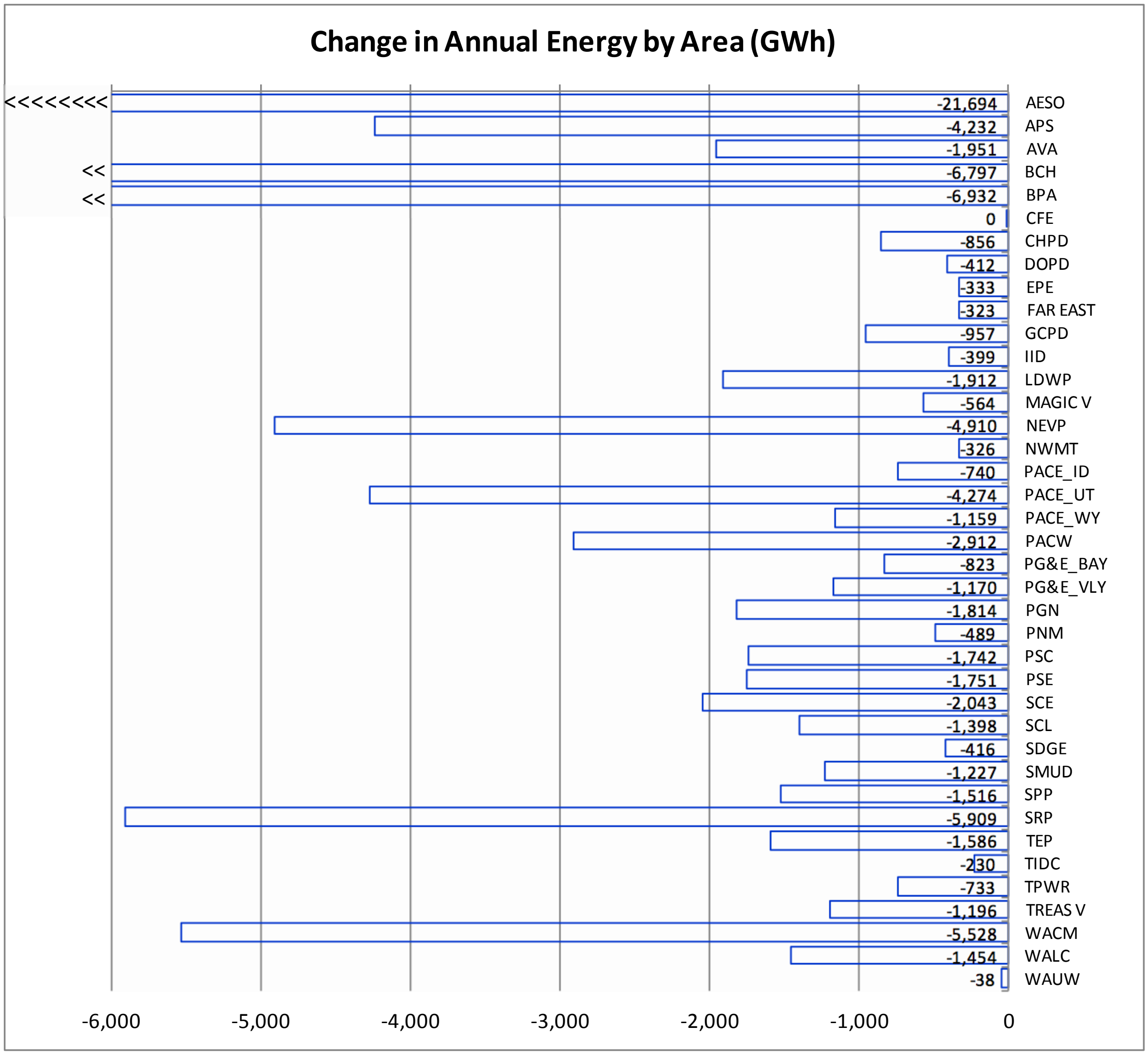


Fig. 2. High DSM/DR/DG case: Change in annual energy from 2022 Common Case. *Source: WECC 2013a.*

However, this outcome—as gauged by utilization metrics—generally did not occur in the analysis.[3] The reason is that the WECC 2022 Common Case assumed that RPS requirements would be met primarily

[3] The paths are in general sets of physical transmission lines. Utilization or congestion metrics gauge how much power is flowing through a path. Specifically, they measure the percentage of time that the flow exceeds 75% (the "U75" metric), 90% ("U90"), or 95% ("U95"), respectively, of the path's "operating transfer capability," the amount

with in-state resources, making it unlikely that any load scenario would have required new transmission for state RPS compliance (WECC 2013a).[4] Another result of the study was that demand-side measures freed up lower cost generation available for export, particularly from the Pacific Northwest (including British Columbia) and the Desert Southwest, thus increasing utilization on a number of paths. This reflects in part the use of production cost modeling for the analysis, which solves for the least cost dispatch across the entire interconnection.

Such congestion results in the High EE/DG/DR case may be unexpected, with lower demand leading to higher utilization. However, it is important to emphasize that, as noted above, the demand-side measures are nevertheless yielding economic benefits by virtue of enabling reallocation of low-cost generation resources in the WECC.

2.2 20-YEAR ANALYSIS

2.2.1 Scenario Inputs

As in the 10-year analysis, for the 20-year analysis LBNL assessed and, as needed, adjusted the basic BA load forecasts to ensure they incorporated existing and already-planned programs and policies. A set of new energy-efficiency projections was then developed using the "statistically-adjusted end-use (SAE)" load forecasting modeling framework (McMenamin and Quan 2010).[5] As noted previously, the 10-year high DSM case was based on the criterion of economic efficiency potential. By contrast, the 20-year efficiency assumptions were akin to those used in technical potential projections and therefore more aggressive (Sanstad et al. 2014). The 20-year DR projections were developed by extending and updating the 10-year scenario.

2.2.2 Energy and Transmission Implications

In contrast to the 10-year analysis, in the 20-year study these SAE-generated aggressive demand-side projections were used in several sets of scenarios. The SPSC oversaw the development and analysis of a high EE/DG/DR scenario in which WECC-wide annual energy (in gigawatt-hours) in 2032 was reduced by 21.6%, and summer peak demand by 22.1%, relative to the 2032 Reference case (Barbose et al. 2014a). The savings by WECC BA are shown in Fig. 3.

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of power that can be transferred through the path while complying with the reliability requirements of the North American Electric Reliability Council.

[4] At the same time, it is also the case that transmission over long distances intrastate can be entailed in meeting RPS requirements, because of distances between the renewable resources and the load.

[5] This framework integrates end-use energy technology detail with econometric modeling.

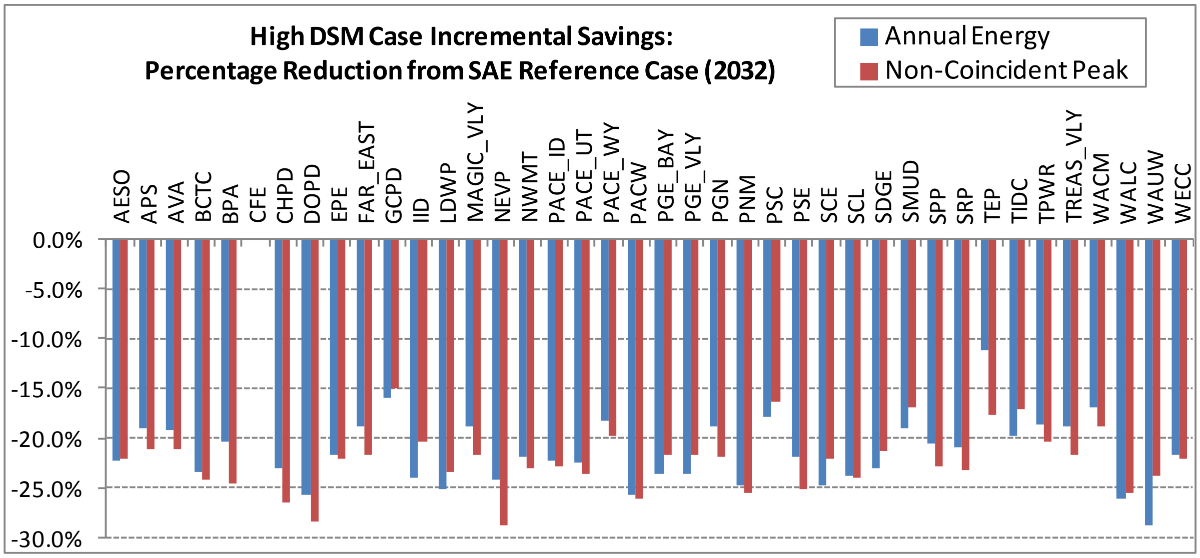
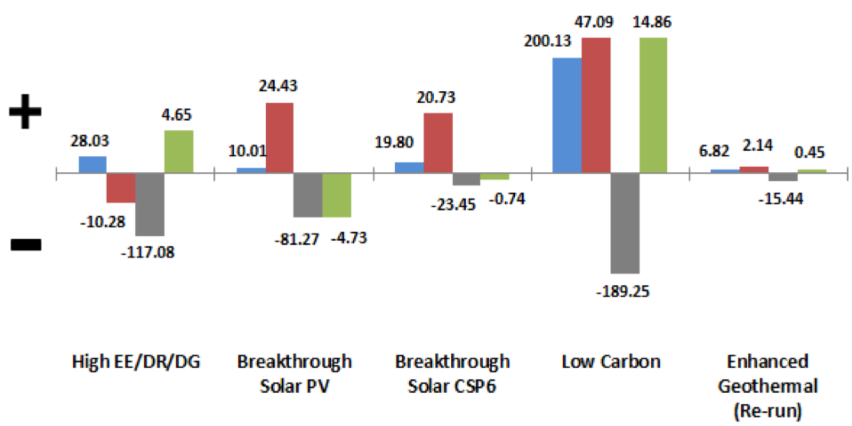


Fig. 3. SAE High DSM case incremental savings relative to SAE reference case. *Source: Barbose et al. (2014a).*

The High DSM/DR/DG scenario, along with others analyzed in the same TEPPC study cycle, was implemented using LTPT, a newly introduced capital expansion optimization model. In addition, a "low-carbon," several "tech breakthrough" scenarios, and a so-called "enhanced geothermal" scenario were developed and analyzed under SPSC auspices.[6] Figure 4 presents reference case values for generation and transmission capital costs, a weighted levelized cost of energy (LCOE), and CO_2 emissions and shows graphically the changes in these quantities across the SPSC scenarios. The High DSM/DR/DG scenario resulted in the fewest optimized transmission additions and therefore the lowest transmission capital costs among all these scenarios. This contrasted with the previously mentioned 10-year finding that certain additional capacity might be warranted in the High DSM/DR/DG scenario. This discrepancy reflects in part the different technical capacity planning tools used in the two horizons (i.e., production cost modeling in the 10-year study and capacity expansion modeling in the 20-year, as described previously), but it was TEPPC's conclusion that the issue will require further analysis to resolve (WECC 2013b).

Metric	Reference Case Value
Generation Capital Cost	$90.97 Billion
Transmission Capital Cost	$28.56 Billion
CO2 Production	329.37 Million Metric Tons
Weighted Average LCOE (No CO2) of All Generation (2011-2032)	$46.74 per MWh



[6] An initial tech breakthrough scenario for geothermal entailed a 50% reduction in capital costs for this technology from their current US national average. This did not result in any geothermal resources being selected by the model. The enhanced geothermal scenario assumed a 60% reduction.

Fig. 4. SPSC 20-year study results comparison (sizes of bars reflect percentage changes). *Source: WECC (2013b).*

2.3 CONCURRENT WECC 20-YEAR SCENARIOS

Concurrent to the SPSC analyses, WECC developed and analyzed four 20-year scenarios in addition to a reference case; these are illustrated and summarized in Fig. 5.

In these WECC scenarios, 100% of the High EE/DG/DR energy savings projections shown in Fig. 3were assumed in Scenario 2, and 50% assumed in Scenario 4.[7] Figure 6 shows cost and CO_2 results for the WECC reference case and the four scenarios. Scenarios 2 and 4 had the highest transmission capital cost, but it is important to emphasize that in these scenarios the demand-side assumptions were integrated with other policy, economic, and technology assumptions, and the results are a function of all these factors, making it difficult to discern the effects of the demand-side factors specifically.

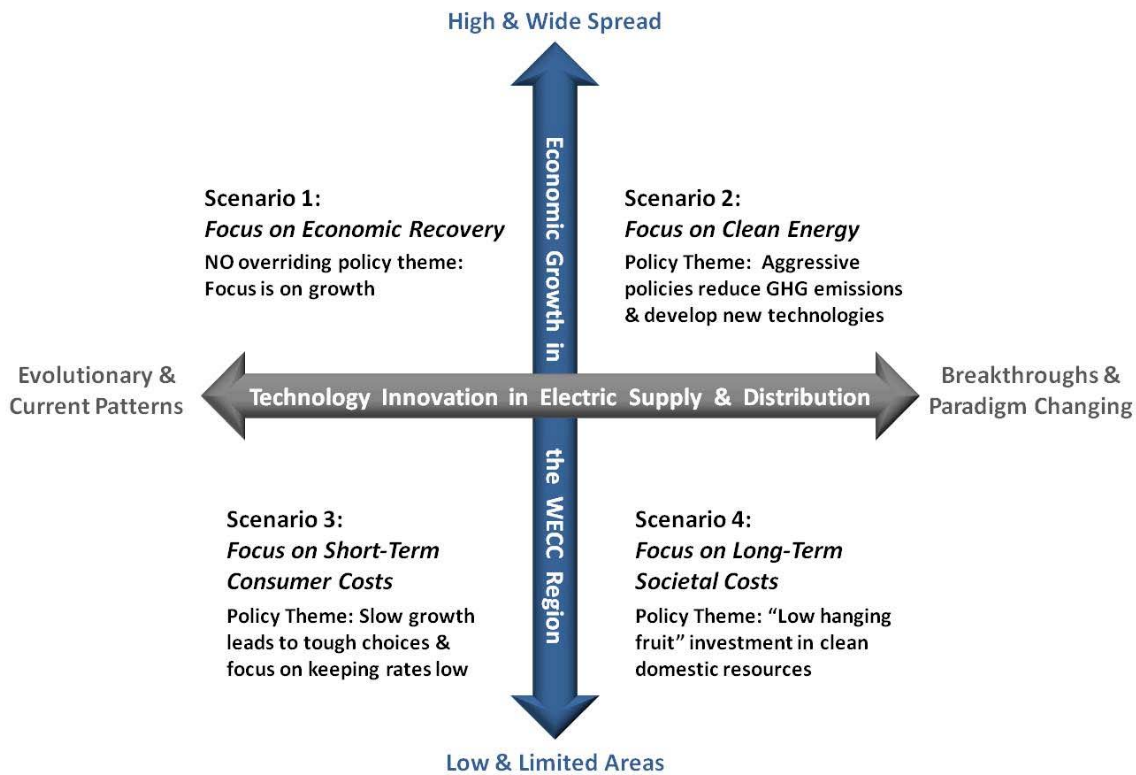


Fig. 5. WECC 20-year scenarios. *Source: WECC (2013b).*

[7] WECC did not report what assumptions were made regarding peak demand in these two cases.

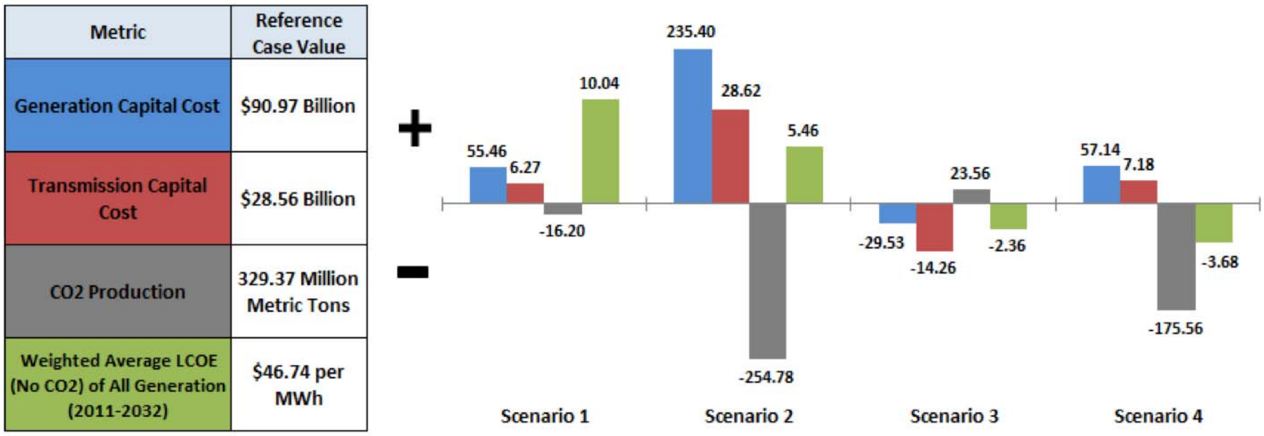


Fig. 6. WECC 20-year study results comparison (sizes of bars reflect percentage changes).
Source: WECC (2013b).

3. DEMAND RESOURCES IN EASTERN TRANSMISSION STUDIES

Between 2010 and 2012 EIPC conducted a major long-term resource and transmission study of the Eastern Interconnection (EI). With guidance from a stakeholder steering committee (SSC) that included representatives from the Eastern Interconnection States' Planning Council among others, the project was conducted in two phases. The first was a 2015–2040 analysis that looked at a broad array of possible future scenarios, while the second focused on a more detailed examination of the grid in 2030 (EIPC 2011, 2012a, 2012b, and 2012c).

In Phase 1, the EI was modeled as 24 regions with single electrical tie-lines between neighboring regions. Figure 7 is a map showing the different regions, and Fig. 8 is a diagram of the baseline capacities across each tie-line. These lines between the regions had transfer capacities in megawatts that the planning authorities set based on their experience in operating the grid.

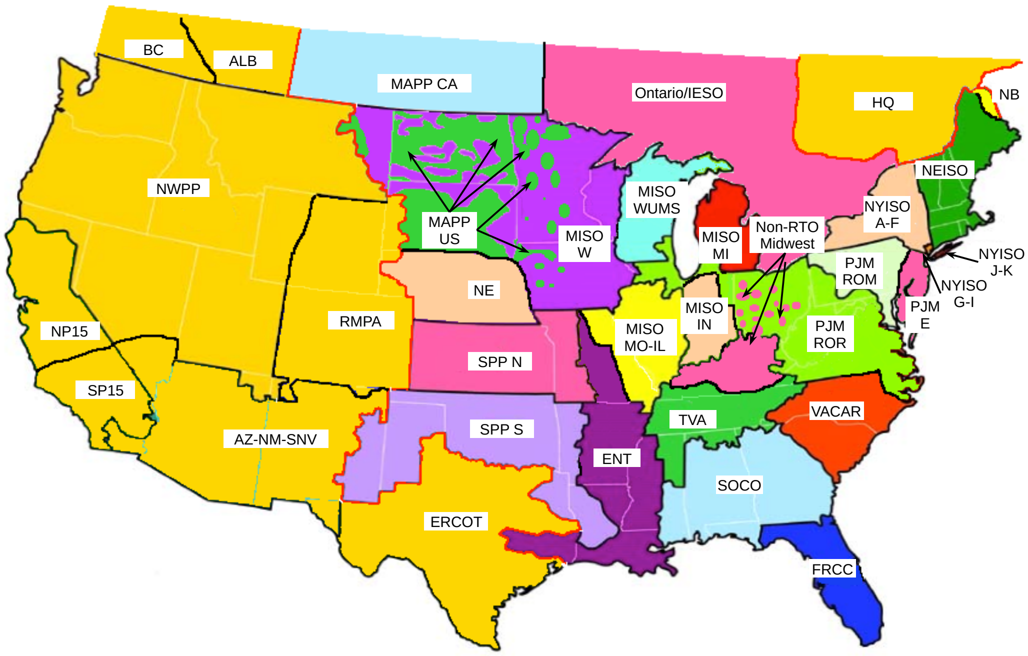


Fig. 7. Map of Eastern Interconnection (EI) regions (EI includes the multicolored, non-gold regions).

In Phase 1 of the study, the term "futures" was used to define a consistent set of input assumptions on technologies, policies, and costs. Eight futures were defined by the SSC in an attempt to cover a wide range of possible policies. The futures ranged from business as usual (BAU) to various CO_2 limits, RPSs, end-user activities, and nuclear resurgence. The eight are listed in Table 1, along with a description and the short label used for each in this report.

A set of sensitivities was defined for each future, but an initial case using the coupled general equilibrium economic model MRN and the electric capacity expansion model NEEM (North American Electricity and Environment Model) had to be run to establish economy-wide, energy-related demands; generation mixes; and prices for each of the futures. The results of these cases could then be used to expand the transmission system (transfer capacities) between regions inside the NEEM model, setting the base case for each future. Following that, sensitivities were run through NEEM that allowed the EIPC and SSC to explore a variety of changes to technologies, costs, demands, or policies.

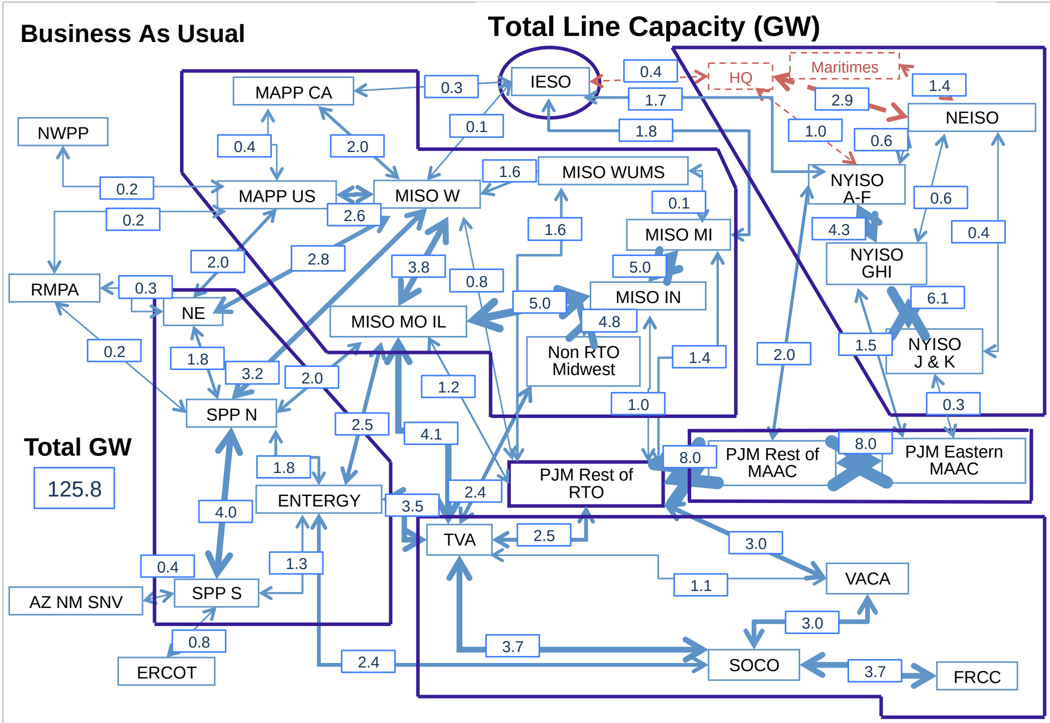


Fig. 8. Baseline interregional transfer capacities.

Table 1. List of futures studied in Phase 1

Future	Label	Definitions
1	BAU	Business as usual scenario
2	CO_2/N	High CO_2 cost scenario, national implementation
3	CO_2/R	High CO_2 cost scenario, regional implementation
4	EE/DR	Aggressive energy efficiency (EE), demand response (DR), and distributed generation (DG)
5	RPS/N	National renewable portfolio standard (RPS), national implementation
6	RPS/R	National RPS, regional implementation
7	NUC	Nuclear resurgence
8	CO_2+	High CO_2 costs scenario with aggressive EE, DR, DG, and nationally implemented RPS

The base input data for all cases included a projected amount of EE, DR, and DG. Future 4 (labeled EE/DR) explicitly increased these three components and explored variations of these in the sensitivities. With end-use demands similar to the future with high EE, low demand growth sensitivities were run in Future 1 (BAU), Future 2 (CO_2/N), and Future 3 (CO_2/R). These different cases in Phase 1 allowed evaluation of the effect of demand resources to some extent. Table 2 shows the load growth through 2030, added transfer capacity beyond the base level, and amount of peak and total electricity transferred interregionally in 2030.

Table 2. Cases for comparison of demand changes

Future and Sensitivity	2011-2030 EI Load Growth (%)	Added Transfer Capacity 2020-2035 (GW)	2030 Maximum All-Hour Inter-Region Flow (GW)	2030 EI Total Transferred Energy (TWh)
1. BAU Base	17%	0	115	297
1. BAU HiLoad	41%	0	112	372

1. BAU LoLoad	-4%	0	113	309
2. CO_2/N Base	2%	40	175	853
2. CO_2/N HiLoad	27%	40	179	793
2. CO_2/N LoLoad	−18%	40	165	770
3. CO_2/R Base	2%	5	122	527
3. CO_2/R HiLoad	27%	5	131	477
3. CO_2/R LoLoad	−18%	5	114	472
4. EE/DR Base	−5%	0	115	334
4. EE/DR Extra Reduction	−22%	0	101	370

The total transfers are plotted against the change in load in Fig. 9. From these one can see that despite large differences in demand growth, the amount of transfers do not change significantly for a given future. Some sensitivities had higher loads than the base but lower transfers (CO_2/N, CO_2/R), while other sensitivities with lower loads than their bases had higher transfers (BAU, EE/DR).

There are some caveats to any insights gained by analyzing these cases. As can be seen in Table 2, the transfer capacity added in each future was fixed during its initial run before the sensitivities were run. With the transfer capacity already fixed, the sensitivities could not directly measure how EE or lowered demand would reduce transfer capacity. A comparison of the EE/DR future to the BAU would have provided some guidance, but because the BAU future had no additional capacity added, there was not an opportunity to see any reduction.

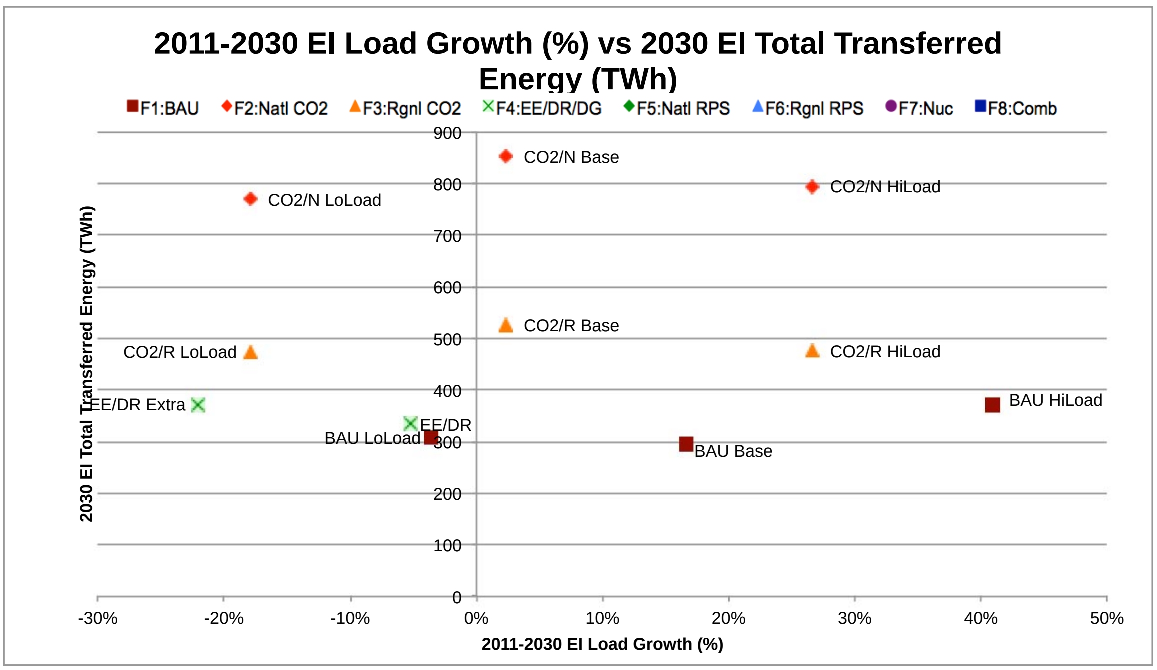


Fig. 9. Eastern Interconnection (EI) growth in demand 2011–2030 versus total interregional transfers.

Regionally, differences in generation were identified that provide some insights. Most regions had similar changes in generation levels as demand increased or decreased. Figure 10 presents the amount of generation by territory (collection of regions) in four futures that had changes in demand included in their sensitivities. Note that the base case in the EE/DR/DG future is closely equivalent to the low load sensitivity in the BAU future, and the lower load sensitivity included a further reduction in demand.

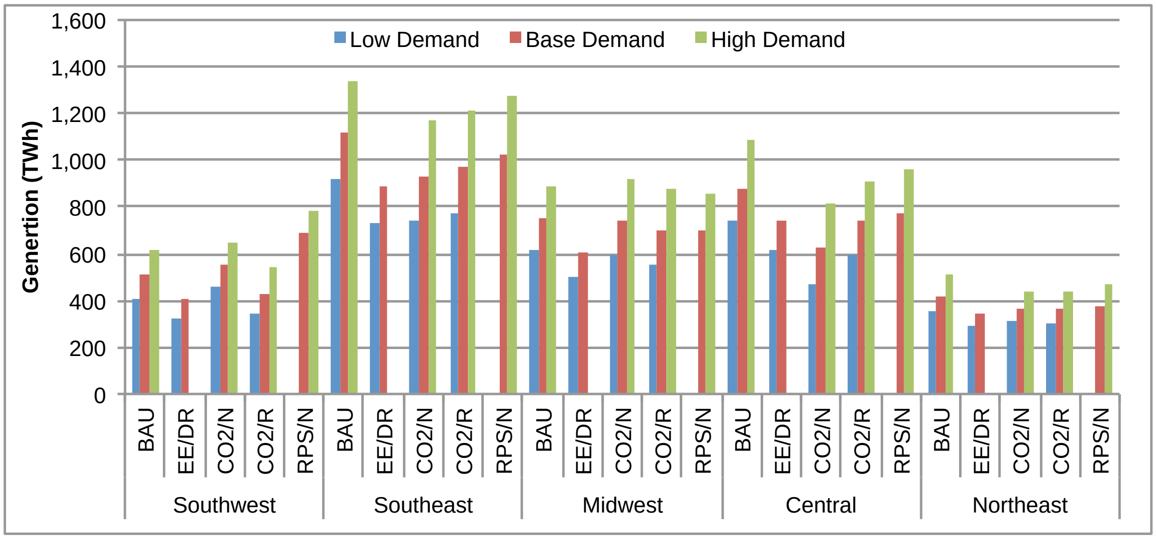


Fig. 10. Eastern Interconnection generation by territory in 2030 under different load growth scenarios.

The territories all show decreased generation with demand lowered. With no change in transmission capacity and little change in actual transfers between regions, it follows that each region increased or decreased its local generation to meet its change in demand. However, in a few futures, certain regional changes stood out. These are highlighted in Table 3, which shows the percentage change in generation for each territory from the base scenario of each future. (The table includes several other futures that also had load growth sensitivities.)

Table 3. Percent change in generation from the base scenario for each future by territory

Future	Sensitivity	Southwest	Southeast	Midwest	Central	Northeast	Total
BAU	Low Load	−19%	−18%	−19%	−16%	−16%	−18%
	High Load	22%	20%	18%	23%	22%	21%
EE/DR	Lower Load	−20%	−19%	−17%	**−17%**	−17%	−18%
CO_2/N	Low Load	−17%	−20%	−19%	**−25%**	−16%	−20%
	High Load	17%	26%	24%	**29%**	20%	24%
CO_2/R	Low Load	−20%	−20%	−21%	−20%	−16%	−20%
	High Load	26%	25%	25%	23%	21%	24%
RPS/N	High Load	**13%**	24%	22%	25%	23%	22%
RPS/R	High Load	21%	22%	23%	19%	24%	21%
NUC	High Load	21%	20%	20%	23%	20%	21%

In the CO_2/N future, the Central region (mainly PJM) had bigger swings in its generation levels than the other regions. In that future, the region imported large amounts from the Midwest, and as shown in a previous study (Hadley and Gotham 2014), the transfers between the regions hit capacity limits much of the time. In the sensitivity with demand increased, the region had to generate this extra load internally, so local generation increased proportionately more (up 29%) than the interconnection-wide average (up 24%). Similarly, even with lower demands the total transfers between the regions were still about the same, filling the lines much of the time. Consequently, proportionally more generation in the Central region was reduced (down 25%) versus the interconnection average (down 20%). Even at lower demands, the system was constrained by the amount of transmission capacity, so the impact of demand reductions on transmission was small. Rather, higher-cost local generation was reduced.

In the RPS/N future, the effect on the Southwest was the opposite of that on the Central region. It exported significant amounts of power to the Southeast and Central regions. The lines were fully loaded much of the time; despite higher demands they could not ship much extra power to the east. As a consequence, the percentage increase in generation for the Southwest was lower than the other regions, up 13% instead of the interconnection average up 22%.

4. DEMAND RESOURCES IN TEXAS TRANSMISSION STUDIES

ERCOT has long had a process for short-term and long-term planning for its electric system, an independent grid with only weak, asynchronous connections to the rest of the country. ERCOT's long-term system assessment (LTSA; ERCOT 2012) is based on scenario analysis to assess potential needs up to 20 years in the future. As did the stakeholders in the Western and Eastern Interconnections, ERCOT received funding from DOE to expand long-term planning under a more varied set of scenarios and enhance the tools and processes needed. Between 2010 and 2012 ERCOT developed a series of scenarios for analysis. The scenarios were based on a BAU forecast of demands, fuel prices, and plant availability. ERCOT then varied such factors as natural gas prices, environmental policies, drought, and technologies (including various combinations of DR, EE, DG, and energy storage).

The ERCOT LTSA report (ERCOT 2012) provides the results of the analysis of the six main scenarios (Table 4). DR potential capacities were available in each scenario, and varying amounts were selected in the model based on their relative cost and value.

Table 4. List of scenarios reported in ERCOT's 2012 long-term system assessment *(Source: ERCOT)*

Scenario	Description	2032 Demand Response (MW)	
		Residential	Industrial
BAU with All Technologies (BAU All Tech) (S1)	Extends today's market conditions to 2032. Available technologies included fossil, renewable, and DR	2,200	500
BAU All Tech with Retirements (S2)	BAU with All Tech plus 13 GW of gas-fired retirements	2,200	500
BAU All Tech with Up-dated Wind Shapes (S3)	BAU with All Tech with modernized wind turbines and updated wind availabilities	0	0
Extended Drought (S5a)	Regional water cost adders included in capacity expansion decision process	0	500
BAU All Tech with High Natural Gas Price (S7)	BAU with updated wind shapes, production tax credit, and natural gas prices increased $5/mmBtu	0	500
Environmental (S8)	Addition of proposed US Environmental Protection Agency regulations on emissions, including greenhouse gases	0	500

None of these cases explicitly considered other demand resources like end-use EE, so it is difficult to draw conclusions on their impacts on transmission needs. Several of the scenarios resulted in significant increases in renewables (updated wind shapes, high natural gas prices, and environmental regulations). The strong Competitive Renewable Energy Zone (CREZ)[8] lines help to negate the need for additional import paths into Dallas-Ft. Worth, but if wind grows beyond CREZ capacity, additional lines from the panhandle will be needed.

[8] The CREZ projects are in response to a public mandate to increase renewable energy in Texas. They are primarily designed to move renewable electricity (up to 18,000 MW of wind capacity) from remote parts of Texas to more heavily populated areas. More information can be found at http://www.texascrezprojects.com/overview.aspx.

ERCOT has used the funding from DOE to continue to improve its long-term analytical capabilities. In July 2014 ERCOT presented the latest LTSA results (ERCOT 2014). Using commercial planning software (specifically PROMOD IV and others) and in-house tools, ERCOT completed generation expansion analyses for 9 of 10 scenarios in the current LTSA. EE, DR, and photovoltaic (PV) DG were added as potential resources, and several scenarios focused on their application. The amounts of EE, distributed PV, and DR selected by the model by 2029 are shown in Table 5.

Table 5. Energy efficiency (EE) and photovoltaic (PV) distributed generation (DG) amounts in ERCOT scenarios
(Source: ERCOT)

Scenario	Energy Efficiency (MW)	PV DG (MW)	2029 Demand Response (MW)	
			Residential	Industrial
Current Trends	686	0	14	58
High Economic Growth	686	0	14	58
Stringent Environmental	686, growing 3%/year; 1,117 in 2029	220 in 2018, 1,057 in 2029	373	1,492
High Resilience	686, growing 3%/year; 1,117 in 2029	220 in 2018, 1,057 in 2029	48	191
High Natural Gas Price	686	0	48	191
Water Stress	686, growing 3%/year; 1,117 in 2029	220 in 2018, 1,057 in 2029	373	1,492
High EE/DG	686, growing 20%/year; 7,063 in 2029	220 in 2018, 1,057 in 2029	480	1,921
High Liquid Natural Gas Price	686	0	14	58
Global Recession	686, growing 3%/year; 1,117 in 2029	220 in 2018, 1,057 in 2029	480	1,921

Figure 11 shows the peak load forecasts used in the different scenarios. The high EE/DG scenario both starts lowest in 2018 and grows slowly but steadily, matching global recession demand levels in the later years. ERCOT is currently in the process of rerunning the high EE/DG scenario to reflect this lower demand forecast; earlier runs applied the reductions to a higher base demand. Figure 12 shows the total capacity by technology in 2029. However, the capacity levels for the high EE/DG scenario will be reduced following the rerun of the case as explained previously. These stacks of capacity have a modification such that the wind total shown is the actual wind capacity times 8.7%, and the solar capacity is the actual times 70%. These are to represent the expected fractions of capacity available during the peak demand.

ERCOT so far has selected four scenarios for a full study of the transmission system: current trends, high economic growth, stringent environmental, and global recession, with a fifth scenario to be selected later. While these may provide insights into the impact of varying peak demands on transmission needs, unless the high EE/DG scenario is the fifth selected, a direct comparison on the effect of EE on transmission needs will not be possible. The global recession scenario is likely to have similar impacts on transmission needs but the reduced demand in the 2020 period may cause some differences. The final report including evaluation of transmission impacts is expected by the end of 2014.

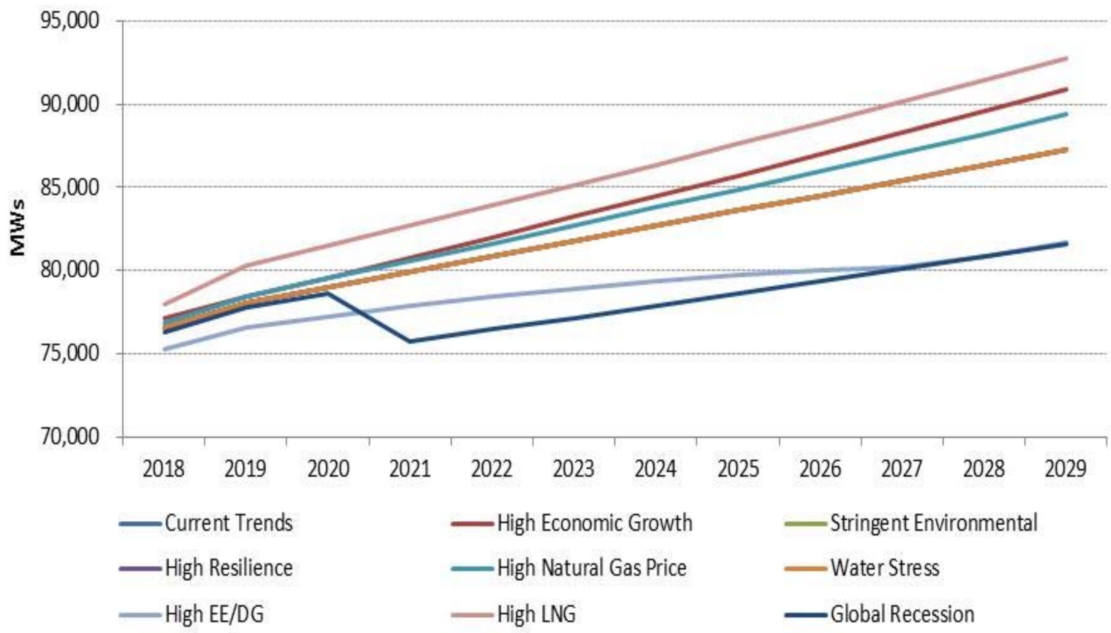


Fig. 11. Peak load forecasts for ERCOT long-term system assessment scenarios.
Source: ERCOT.

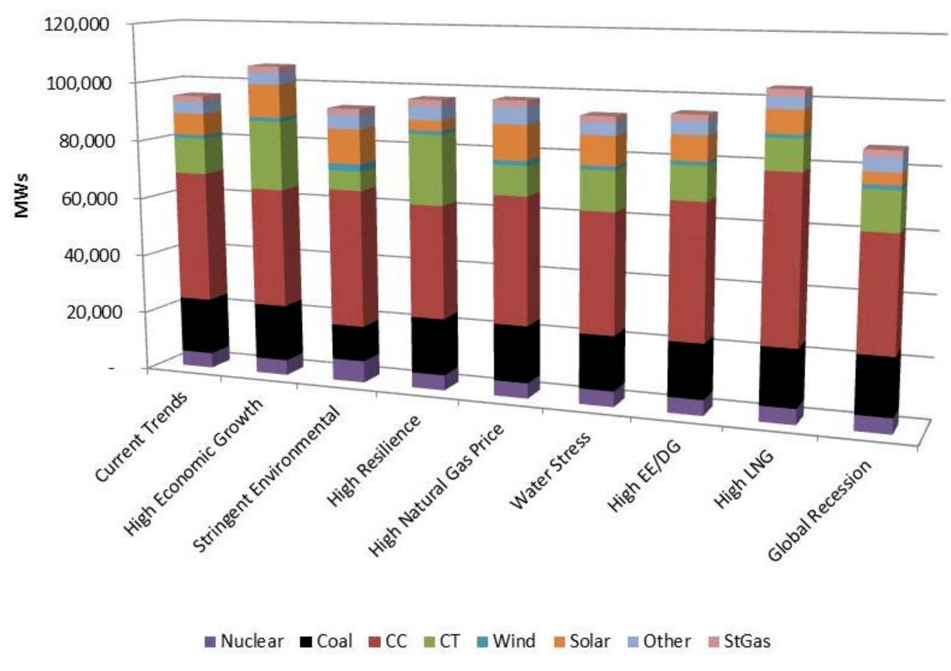


Fig. 12. Total capacity by technology type in 2029. Wind total times 8.7%; solar total times 70%. High EE/DG results are currently under revision. *Source: ERCOT.*

5. SUMMARY

The first installment of the Quadrennial Energy Review is focusing on the country's transmission, storage, and distribution infrastructure. This paper considers the question of whether and how demand resources (EE, DR, and DG) will impact this infrastructure. Recent cancellations of transmission projects due to lower demand suggests that there is a connection.

Five rationales for transmission were identified, and the impacts of demand resources on these were discussed.

- **Interconnection:** Reduced demand generally lowers the need for new generation and consequent connections to the grid. However, connections to provide backup or voltage support may still be required, but these will be largely on the distribution system rather than transmission.

- **Reliability:** Reduced demands lower the needed amount of reserves. In addition, DR can serve to provide reserves, thereby freeing existing generation and transmission assets to provide power.

- **Economics:** Demand resources are at or near loads and so avoid the cost of distant generation, transmission, and losses. On the other hand, lower demand near low-cost generation may increase the use of transmission as that power seeks more distant markets.

- **Replacement:** By lowering demand, EE and DR may lengthen the lifespan of T&D equipment. However, utilities may need to upgrade equipment early for DG implementation, and smart grid systems that enable demand resources may make older equipment obsolete.

- **Environmental:** Demand resources can provide environmentally attractive alternatives to transmission plus distant generation. Portfolio standards may recognize these resources for meeting clean energy standards. Local clean generation may need to transmit further distances if local demand is reduced.

DOE funded long-range transmission studies of the three major interconnections, which analyzed the effect of demand resources on both energy demand and supply and on the transmission systems themselves. Following are some insights from these studies.

The Western Interconnection studies included both 10- and 20-year scenarios incorporating high EE/DG/DR projections. The following were among the results.

- In the 10-year case, demand-side policies do not reduce overall future western transmission needs but do enable more economically efficient (lower cost) allocation of power across the West.

- In the 20-year study, aggressive demand-side policies result in the fewest optimized transmission additions among multiple scenarios, yielding a 36% transmission capital cost reduction relative to the base or common case; they also provided substantial CO_2 emissions reductions.

The Eastern Interconnection study examined a number of futures through 2030 and included sensitivities with higher or lower demand. The results indicated the following.

- With transmission capacity fixed before demand was lowered or raised, there was little change in total transmission flows across the entire EI despite changes in demand. Low-cost and/or clean resources used the capacity available to export to other regions.

- Reductions in demand mainly reduced generation locally instead of reducing transmission; exporting regions had proportionally less reduction in local generation while importing regions had more. In high wind scenarios the lines from exporting regions were frequently fully loaded, so any local demand reduction would add to the untapped supply of available low-cost power and further drive the need for additional transmission to displace more expensive power in other regions.

The earlier ERCOT study funded by DOE began with scenarios including changes to demand, generation, fuel prices, and environmental policies but only evaluated transmission changes for a subset that did not include demand resources. A current study is evaluating more explicitly demand resource effects on generation and transmission, but results are not complete at this time.

Several caveats should be noted. In all three of these studies demand resources were evaluated in conjunction with other parameters (e.g., CO_2 emission limits, RPS requirements), and limitations on transmission addition changes between scenarios made understanding the role of demand resources difficult. In many cases the role of demand resources had to be inferred based on the results available. Because demand resources were only a small part of the full analyses being conducted, they were not singled out for dedicated analysis.

Study of the interactions between demand resources and transmission is in its early stages, and more can be done to better understand the relationship. A major difficulty is the current serial nature of modeling resource expansion and transmission capacity. Capacity expansion models generally use a reduced model of the transmission grid that does not truly capture the physical nature of power flow, so they cannot effectively plan future generation and transmission systems. Also, models have only begun to incorporate demand resources realistically as variables in their evaluations. Planners and modelers are beginning to take these factors into account, creating co-optimizing models and better representations of demand resources. Increases in computing power and funding of other studies will further help to advance the science in integrated electric planning.

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