Senate Bill 350 Study

Volume VI: Load Diversity Analysis

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Senate Bill 350 Study

The Impacts of a Regional ISO-Operated Power Market on California

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Volume VI. Load Diversity Analysis

A. Overview

Regionalization of the California ISO (ISO) would yield savings due to regional load diversity, which allows for reduced capital investments in supply resources to meet system-wide and local resource adequacy requirements. These resource adequacy-related benefits of regional market integration can be assessed from either a reliability perspective (*e.g.*, by holding generation investments constant and analyzing the benefit of improved reliability) or from an investment-cost perspective (*e.g.*, by holding the level of reliability constant and analyzing the reduction in generation investment needs).

For this study, we analyze the likely benefits associated with capturing the diversity of load patterns across a larger regional market by holding the reliability requirements constant and estimating the reduction in generation capacity needs due to market integration. This analysis measures "load diversity" as the degree to which individual balancing area (BA) peak loads occur at different times and seasons, which leads to a coincident peak load for the combined footprint that is lower than the sum of the individual BA-internal peak loads. Figure 1 illustrates how load diversity leads to lower combined peaks. This reduction in coincident peak load is then used to estimate the generation investment cost savings offered by a regional market.[1]

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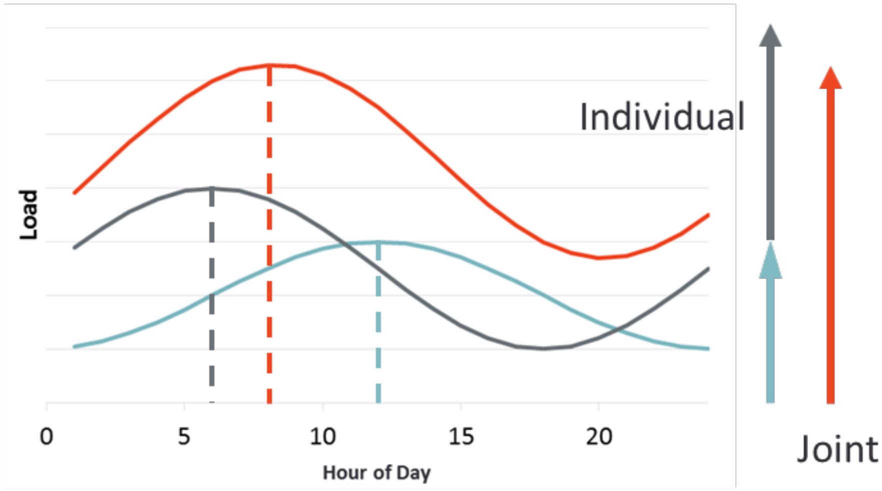
[1] Energy + Environmental Economics, "Regional Coordination in the West: Benefits of PacifiCorp and California ISO Integration," October 2015. Available at: http://www.caiso.com/informed/Pages/RegionalEnergyMarket/BenefitsofaRegionalEnergyMarket.aspx

Figure 1: Reduction in Capacity Due to Load Diversity



Note: Two load profiles (blue curve and grey curve) are combined to create a single joint profile (red curve). Since the peaks of the blue and grey profiles do not coincide, the peak of the joint load profile is less than the sum of the peaks of the individual profiles.

A similar methodology was used by E3 in the PAC Integration study and by Entergy in its 2011 study of the expected benefits and costs of joining MISO.[2] That such benefits are realized by members of regional markets is demonstrated by Entergy when it reported its actually-realized benefits after its first year of MISO membership.[3] MISO's own retrospective analysis confirmed the load diversity benefits of Entergy's membership. In its most recent MISO Value Proposition, the RTO found that the MISO South region, which includes Entergy, achieved $560–$750 million in load diversity benefits.[4] We use historical hourly BA loads from 2006 to 2014 to estimate typical annual peak loads and the amount of resources needed to meet the planning reserve requirement of each BA with and without a regional market. The data show that some

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2 Entergy, "An Evaluation of the Alternative Transmission Arrangements Available to the Entergy Operating Companies And Support for Proposal to Join MISO," May 12, 2011. Available at: http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=bc5c1788-4ce0-4daa-9ad0-71f09ad43643

Entergy anticipated that its capacity requirement would be 1,400 MW less (approximately 6% of peak load) as a MISO member than as a standalone entity, due to the fact that its effective reserve margin would be 12% as a MISO member, compared to 17%–20% as a standalone entity.

3 Entergy, "Estimate of MISO Savings," Presented by: Entergy Operating Companies, August 2015, Available at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/ICT%20Materials/ERSC/2015/20150811/20150811%20ERSC%20Item%2006%20Benefits%20of%20MISO%20Membership.pdf

4 MISO, "2015 Value Proposition Stakeholder Review Meeting," January 21, 2016, Available at: https://www.misoenergy.org/WhatWeDo/ValueProposition

BAs are summer-peaking while others are winter-peaking—and even those that peak in the same season will generally reach their peak load on different days and/or at different times of day. Capturing the benefits of this load diversity across a larger footprint through a regional market means that less generating capacity is needed on a region-wide basis. Because some BAs rely on the possibility of imports from neighboring BAs to reduce their internal resource needs, we estimate the extent to which this may already occur to derive the incremental savings that could be achieved through full coordination among all BAs within the assumed market region.

Our estimates of the load diversity benefits of a regional market are likely conservative for several reasons. First, we have not monetized the reliability-related benefits of load diversity in an integrated market (though we have discussed these benefits qualitatively in another volume). This means, for instance, that the low-end of our reported savings for PacifiCorp in 2020 are almost certainly too low. Second, our methodology does not consider the additional benefits that would accrue given the anticipated retirement of substantial existing generation in California. In a high-retirements scenario, the avoided costs in 2030 associated with load diversity could well exceed the $75/kW-year we assumed for California in that year. Third, the prospective study of Entergy joining MISO used a similar methodology to estimate load diversity benefits. After-the-fact analysis confirmed that the study had under-estimated the benefits. In fact, MISO CEO John Bear stated that the benefits achieved in the first year of Entergy joining MISO exceeded anticipated benefits by $220–$450 million.[5] Fourth, while local resource adequacy requirements may not change under regionalization, there would be opportunity to benefit from regional planning that could expand the options to solve local constraints more cost effectively. And finally, flexible capacity requirement and the cost of providing the necessary flexibility will be reduced with greater diversity of variability and loads and resources. These resource adequacy, local, and flexible capacity cost benefits are not captured in our load diversity analysis.

The next sections describe our methodology and calculations for estimating load diversity savings in the 2020 and 2030 time frames. For the 2020 case, we estimate savings for a regional market footprint consisting only of the ISO and PacifiCorp. For the 2030 case, we estimate savings for a hypothetical integrated market footprint consisting of the U.S. portion of WECC with the exception of the Federal Power Marketing Administrations ("PMAs").

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[5] Watson, M. "MISO South benefits more than forecast: CEO," February 9, 2015, Platts Energy Trader, Available: https://online.platts.com/PPS/P=m&e=1423533931204.-8681191587350061510/PET_20150209.xml?artnum=c2b5a9cf9-d2ba-4195-8075-76a12fd750b7_41

B. RESULTS SUMMARY

Before discussing our methodology in detail, we first summarize our results in 2020 and 2030. In our baseline, we assumed that only the ISO and PacifiCorp would participate in the regional market in 2020. Table 1 summarizes load diversity capacity cost savings estimated in 2020 under for this scenario. In California in 2020, we used a $35/kW-year avoided cost of capacity savings, reflecting the average Resource Adequacy Requirement contract price for 2012-2016.[6] Under these assumptions, we find that regionalization leads to 184 MW of capacity savings in California, corresponding to $6 million per year.

In PacifiCorp, we assumed an avoided cost of capacity of $0-39/kW-year in 2020. The high end of this range reflects PacifiCorp's estimated brownfield cost of building two new CCs as described in the PacifiCorp Integration Study.[7] The low end of the range reflects the fact that these new plants might not have been built prior to 2020. Under these assumptions, we find that regionalization leads to savings of 776 MW for PacifiCorp, corresponding to $0 - $30 million/year in annual savings. Savings in PacifiCorp can be increased by up to 392 MW, or $15 million/year, with additional transmission capacity between PacifiCorp and CAISO.

We also considered a sensitivity case that includes a market footprint consisting of all of the U.S. WECC, except the Power Marketing Authorities (PMAs). This is the same footprint that we model in 2030. With the full regional footprint, savings in 2020 increase to 1,657 MW and $58 million/year in California (which includes all California BAs in this sensitivity case) and to 2,388 MW and $84 million/year in the rest of WECC (which now includes all of the U.S. WECC outside of California, except the PMAs).

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6 This value is based on the PAC Integration study's reported average California Resource Adequacy Requirement (RAR) Contract Price for existing generation of $34.80/kW-year for 2012–2016.

7 See p. 13 of: Energy + Environmental Economics (E3), "Regional Coordination in the West: Benefits of PacifiCorp and California ISO Integration," October 2015, Technical Appendix, Available: http://www.caiso.com/informed/Pages/RegionalEnergyMarket/BenefitsofaRegionalEnergyMarket.aspx

Table 1: 2020 Baseline Load Diversity Benefit and Annual Capacity Cost Savings

	CAISO	PacifiCorp
Capacity Benefit of Load Diversity with Current Transmission	**184 MW** (0.39%)	**776 MW** (5.86%)
Additional Capacity Savings with Transmission Upgrades	-	392 MW (2.96%)
Value of Capacity Benefit with Current Transmission ($ millions/year)	**$6MM**	**$0–30**
Additional Value of Capacity Benefit with Transmission Upgrades ($ millions/year)	-	$0–15

In 2030, we assumed that all California Balancing Authorities participated in the regional market. Additionally, the rest of the WECC, with the exception of the Canadian provinces and the PMAs, also participates. In our baseline analysis, we assumed an avoided cost of capacity of $75/kW-year in California, reflecting the fact that California will likely approach, but not yet reach, resource balance by 2030. We also report savings for avoided costs of capacity in California ranging from as low as the current Resource Adequacy contract prices ($35/kW-year) to the full Net Cost of New Entry in California ($150/kW-year).[8] In the rest of WECC, we assumed an avoided cost of capacity of $100/kW-year in our baseline analysis. We also report savings for avoided costs of capacity in the rest of WECC ranging from as low as $39/kW-year (current brownfield CC cost in PacifiCorp) to as high as $120/kW-year (nation-wide net cost of new entry).[9]

Table 2 summarizes load diversity capacity cost savings in 2030. We find that a regional market will reduce capacity requirements of California balancing areas by 1,594 MW, saving $120 million/year (with a range from $56-239 million/year). Savings in California can be increased by a further 145 MW, or $11 million/year (ranging from $5-22 million/year) with additional transmission capacity. In the rest of the region, the regional market would reduce capacity requirements by 2,665 MW, or $266 million/year (with a range of $104-320

8 This value represents the Net Cost of New Entry (Net CONE) in California. CAISO's Department of Market Monitoring recently reported Net CONE ranging from $120 - $160/kW-yr. See p. 52-54 of http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf.

9 LAZARD, "Lazard's Levelized Cost of Entry Analysis – Version 9.0," November 2015, Available: https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf

million/year). Savings in the rest of the region can be increased by a further 1,942 MW, or $194 million/year (ranging from $76-233 million/year) with additional transmission capacity.

Table 2: 2030 Load Diversity Benefit and Annual Capacity Cost Savings

	California	Rest of Region
Load Diversity Benefits Already Captured	0 MW	4,481 MW
Capacity Benefit from Regional Load Diversity with Current Transmission	**1,594 MW** (2.79%)	**2,665 MW** (3.12%)
Additional Capacity Benefit with Transmission Upgrades	145 MW (0.25%)	1,942 MW (2.28%)
Capacity Cost Savings with Current Transmission ($ millions/year)	**$120** ($56–239)	**$266** ($104–320)
Additional Capacity Cost Savings with Transmission Upgrades ($ millions/yr)	$11 ($5–22)	$194 ($76–233)

C. Methodology

Our approach to estimate the capacity savings due to regional load diversity involves 4 steps:

1. Estimate how much each BA's peak load coincides with the region's peak load based on historical hourly loads, and derive the average "coincidence factor" for each BA;
2. Use BAs' stated planning reserve margins to determine each BA's planning reserve requirements as standalone entities (these planning reserve margins typically reflect capacity savings achieved by the BAs within each WECC sub-region);
3. Use the coincidence factors to estimate the capacity requirements of BAs when operating within the regional market;
4. Estimate (a) the extent to which each BA is able to achieve the identified capacity savings given the likely limits on the existing transmission grid; and (b) the additional capacity savings that would become available if our analysis underestimated the capability of the existing transmission grid or if transmission expansion were to occur in the future.

D. ESTIMATION OF PEAK LOAD COINCIDENCE FACTORS

We gathered the historical hourly load data from 2006 to 2014 for all BAs in the U.S. portion of WECC, as reported by the BAs in their FERC Form 714 filings.[10] For each year, we estimated the non-coincident peak loads for each BA and the BA's load level that is coincident with the regional market's peak load. We used the difference between the two load levels to estimate a "coincidence factor," which is defined as the ratio of the BA's share of the regional market's peak to its own internal (non-coincident) peak. We first estimate the coincidence factor of each BA for each year between 2006 and 2014[11] and then derive an approximation for a "weather normalized" coincidence factor by using the median of the annual coincidence factors for each BA. To further reduce weather-related noise in the data, the annual coincidence factors are estimated as the 4-coincident-peak ("4CP") loads, by taking each BA's internal load and regional market average load during the highest four hourly loads for each year.[12]

Next, we applied the estimated coincidence factors to projected future peak loads to estimate each BA's future load levels that are coincident with the assumed regional market's peak load in the 2020 and 2030 cases. From there, we estimated the difference between (1) the capacity requirements that each BA would need to meet its own planning reserve requirements as standalone entities; and (2) their share of the regional market's coincident peak to estimate the likely range of capacity savings in a regional market, subject to conservative estimates of how much of these savings have been captured or can be accommodated through the existing transmission grid.

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10 In addition to Canadian and Mexican BAs our analysis excluded several small BAs in the WECC for which FERC Form 714 data were not available: Arlington Valley, Constellation Energy Control and Dispatch, Gila River Maricopa Arizona, Griffith Energy, Harquahala Generating Maricopa Arizona, NaturEner Glacier Wind Energy, NaturEner West Wind.

11 As will be discussed below, for the 2030 regional market case, we calculated coincidence factors in two steps by first considering load diversity within each WECC subregion and then considering load diversity between the WECC subregions.

12 The 4CP is a recognized method for estimating peak load that minimizes the impact of minor fluctuations in weather and other factors affecting the demand for electricity from year to year. For example, the method is used by ERCOT to allocate transmission costs. See: http://www.ercot.com/content/wcm/training_courses/104/ercot_demand_response_2014_ots.pptx

E. Generating Capacity Cost Savings from Load Diversity in 2020

For 2020, we assumed that an integrated market footprint would consist only of the ISO and PacifiCorp. We estimated the two BA's capacity needs based on peak loads and their respective existing planning reserve margins of 15% and 13%, respectively. Then, we assumed that, when integrated, both the ISO and PacifiCorp would continue to retain their current planning reserve margins to satisfy resource adequacy requirements.[13]

Table 1 shows our calculation of 2020 capacity savings for the ISO and PacifiCorp. The potential capacity savings for PacifiCorp are substantially larger than those for the ISO. This result is driven by the fact that PacifiCorp's contribution to the combined regional market peak is substantially less than the ISO's. However, PacifiCorp's capacity savings are limited by its 776 MW import capability from the ISO. In contrast, the ISO is able to achieve the full potential capacity savings of 184 MW without the need to add to the 982 MW of assumed transmission capability for imports from PacifiCorp.

Row 2 of Table 1 shows the two BA's internal (non-coincident) peaks. Multiplying this non-coincident peak with the *Median Coincidence Factor* in row 3 yields the BAs' shares of the regional market peak, shown in row 4. Potential capacity savings are estimated by multiplying the BA's reserve requirement (in row 1) by the difference between the non-coincident peak and the BA's share of regional market peak, as shown in row 5. These savings are then limited by the assumed maximum transmission import capacity shown in row 6.

Thus, we estimated the ISO and PacifiCorp's reduction in installed generating capacity needs as the lesser of (a) the potential capacity savings and (b) the transmission import capability from the other area (776 MW from ISO to PAC and 982 MW from PacifiCorp to the ISO). The MW savings achievable with the assumed transmission capability is shown in row 7, and additional MW savings associated with potential future transmission upgrades are shown in row 8.

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13 Similar to the E3 PAC Integration study, we do not alter PacifiCorp's reserve margin in the integrated market case. If we had assumed that PacifiCorp's reserve margin matched the ISO's 15% when part of the regional market, PacifiCorp's capacity savings achievable with current transmission would not change, but the savings achievable through added transmission capability would decrease by approximately 240 MW.

Table 3: Estimated Generating Capacity Cost Savings from Load Diversity in 2020
All results reported in 2016 dollars

		ISO	PacifiCorp	ISO+PAC Total
Capacity Requirement	[1]	115.0%	113.0%	
Non-Coincident Peak (MW)	[2]	47,010	13,234	60,244
Median Coincidence Factor	[3]	99.7%	92.2%	
BA's Share of Regional Market Peak (MW)	[4]	46,849	12,201	59,050
Potential Capacity Savings (MW)	[5]	184	1,168	1,352
Maximum Transmission Import Capability (MW)	[6]	982	776	
Savings w/ Current Transmission (MW)	[7]	184	776	960
Savings Requiring Transmission Upgrades (MW)	[8]	0	392	392
Avoided Cost of Capacity Savings ($/kW-yr)	[9]	$35	$0–$39	
Total Avoided Cost w/ Current Transmission ($ million/yr)	[10]	$6	$0–$30	$6–$37

Sources and Notes:
[1]: Based on PacifiCorp 2014 IRP and the ISO's published reserve margins.
[2]: Forecast 2020 Non-Coincident Peak Loads. ISO from 2015 IEPR, equal to CEC "Mid Baseline Case." PacifiCorp from 2015 LAR Peak and Energy forecast, PACE + PACW coincident peak.
[3]: Median of annual coincidence factors calculated based on 4CP of hourly load profiles from 2006 to 2014.
[4]: [2] * [3]
[5]: [1] * ([2] – [4])
[6]: Contracted import capability for the ISO and PacifiCorp.
[7]: Minimum of [5] and [6]
[8]: [5] – [7]
[9]: ISO's value reflects 2012–2016 weighted-average resource adequacy contract prices. High end of PacifiCorp range reflects capacity cost net of energy margins for two units as reported in the 2015 IRP. The low end reflects the fact that these new units are not expected to come online before 2020.
[10]: [9] * [7]

Row 9 estimates the avoided cost of capacity in 2020 for the ISO by using a 2012–2016 weighted average capacity contract price of $35/kW-year.[14] For PacifiCorp, we used a range from $0/kW-year to $39/kW-year based on the capacity cost (net of energy margins) of two new generating units in PacifiCorp's 2015 Integrated Resource Plan ("IRP"), as reported in E3's PAC Integration study.[15] Since PacifiCorp's 2015 IRP reported that the new generating units would not be needed until sometime after 2020, we estimated a low end of our range that assumes that the capacity savings would have no value in 2020. (Zero is a very conservative lower bound because load diversity would increase reliability and the higher reliability would have a non-zero

14 This value is based on the PAC Integration study's reported average California Resource Adequacy Requirement (RAR) Contract Price for existing generation of $34.80/kW-year for 2012–2016.

15 The E3 PAC Integration study reports an average capacity price net of energy margins of $37.50/kW-year in 2014 dollars, which we inflate to 2016 dollars at 2%.

value.) The resulting estimates of the potential savings for the combined region range from $6 million to $37 million in 2020, as shown in row 10.

F. GENERATING CAPACITY COST SAVINGS FROM LOAD DIVERSITY IN 2030

We applied the same approach to the 2030 analysis by utilizing each BA's reserve margins and then estimating the regional market's reserve margin based on coincidence factors. For several BAs we rely on recently-published Integrated Resource Plans (Nevada Power, PacifiCorp, Arizona Public Service, Tucson Electric Power, and Puget Sound) for the planning reserve margin requirements as the relevant metric for the individual stand-alone cases. For the remaining BAs, we used the WECC-determined planning reserve margins for the subregion where the BA is located.[16]

Because the BAs are, to some extent, taking advantage of the load diversity within their WECC subregions, we first estimated the amount of load diversity savings upon which those BAs already rely before estimating the incremental amount that they could enjoy through market integration.[17]

Table 2 at the end of this section is a summary table that includes the resulting estimates at various steps of the analysis and reports the findings. The table reports savings separately for California (*i.e.*, the CAISO, LADWP, BANC, IID, and TID balancing areas) and the Rest of Region (*i.e.*, remaining balancing areas in the U.S. WECC, except the PMAs).

We estimated the capacity savings due to load diversity in 2030 with two steps. In the first step, we estimated the full extent to which a BA can share capacity within its existing WECC subregion. We did so by comparing (1) the installed capacity needs using the WECC-determined planning reserve margins when considering the BAs' shares of subregional coincident peak loads with (2) the capacity needs required to meet reserve margins today. Row 3 of Table 2 shows the

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16 NERC, "2015 Long-Term Reliability Assessment," December, 2015, pp. 78 – 85, Available: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2015LTRA%20-%20Final%20Report.pdf

17 For example, Puget Sound's 2013 IRP reports a planning reserve margin of 13.5% for 2014–2015 and a capacity requirement of 6,000 MW based on peak load of 5,300 MW. The document shows that 1,600 MW of import capability is used to meet its capacity requirement and only 4,400 MW is held locally. This implies an effective *internal* reserve requirement of 4,400 MW / 5,300 MW = 83% of peak load.

average coincidence factor of BAs in California and the Rest of Region. The estimated total savings that BAs can capture within their subregions are shown in row 5 of Table 2.

Based on our review of individual BAs' IRPs, we were able to estimate the extent to which some of these savings are captured today by some of the BAs. Of the remaining incremental subregional savings, some of them are likely limited by the simultaneous transmission import constraints (conservatively estimated) on the existing grid. For example, the remaining subregional savings in the Rest of Region are limited largely due to limits on import capability into Portland General Electric (PGE) and Puget Sound. The within-subregion savings in California are all attributable to LADWP, TID, and IID joining the assumed regional market. The ISO itself does not benefit from subregional diversity, because its internal peak load occurs in the same hour as the coincident peak of the California subregion.[18]

To estimate the potential incremental benefits from load diversity within each subregion, we subtract from row 5 the amount that BAs already capture today (shown in row 6). The difference between Rows 5 and 6 is then compared to a conservative estimate of simultaneous transmission import capabilities (as explained below) for each BA from within its subregion, after accounting for the import capability used to achieve the savings in row 6. The estimated incremental subregional load-diversity savings that can be captured without additional transmission are shown in row 7.

In the second step, we use the same approach to estimate the potential savings that could be achieved by sharing capacity across subregions in the entire regional market's footprint (U.S. portion of WECC without the PMAs). As before, we estimate the capacity savings after accounting for the WECC-determined planning reserve margins and the subregional shares of the coincident peak load of the assumed regional market's footprint. The resulting potential capacity savings of integrating WECC subregions with the market's footprint are then shown in row 11.

As is clear from comparing rows 5 and 11, the potential savings from integrating portions of WECC subregions into the larger regional market footprint are larger than the estimated subregional savings, reflecting that a substantial amount of load diversity across the subregions

18 BANC does not contribute to the total capacity savings in California because it is import-constrained.

can be captured by the Regional Market. These region-wide savings are generally less constrained by transmission limitations than the within-subregion savings.

As discussed above, we observe that some BAs are taking advantage of load diversity. They do so by assuming that spot-market imports from neighboring BAs can be used to avoid loss of load events in their area. This resource adequacy benefit of imports is either reflected in a reduction in the BA's planning reserve margin (as is the case for PacifiCorp)[19] or the explicit assumption that a portion of the planning reserve requirements can be met through uncommitted transmission import capability rather than through BA-internal resources (as is the case for Puget Sound).[20] In the case of Puget Sound, we calculated total subregional load diversity benefits equal to approximately 35% of its internal peak load, but estimated (from the company's IRP filing) that most of these load diversity savings—but for 4% of its internal peak load—are already realized today. In other words, the extent to which BAs are taking advantage of load diversity benefits within their region is reflected in BA-internal planning reserve margins (that need to be satisfied through BA-internal resources), which are lower compared to the WECC-determined planning reserve margins for the entire subregion. Because we were not able to gather the necessary information from all BAs but recognized that they will likely be able to take advantage of load diversity savings today, we used the WECC-determined planning reserve margins for those BAs but, based on the Puget Sound example, we limited total load-diversity savings to a maximum of 4% of each of these BA's non-coincident peak load.

To estimate the extent to which transmission constraints may limit the realization of load-diversity benefits, we identified the available intertie capabilities between balancing areas using

19 PacifiCorp's planning reserve margin (which needs to be satisfied through committed BA-internal resources) of 13% is below the WECC subregional reserve margin of 15.4% because of the load diversity and PacifiCorp's interties with neighboring balancing areas. PacifiCorp, "2015 Integrated Resource Plan Volume 2 – Appendices," March 2015. Available at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol2-Appendices.pdf

20 Puget Sound's IRP shows that it allows uncommitted imports to satisfy 1,600 MW of the total resources needed to achieve its 13.5% planning reserve margin. Puget Sound, "2013 Integrated Resource Plan Chapters 1–7," May 2013. Available at: https://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_Chapters.pdf. This IRP specification can be translated to Puget having to meet only 83% of its peak load through BA-internal resources.

the transmission capability data published by WECC's Loads and Resources subcommittee.[21] The model provides summer and winter transfer limits between 19 zones in the WECC. We used the lower of the two seasonal limits, which usually occurs in the summer. Figure 1 shows the summer transfer limits between zones.

To derive a conservative estimate of the maximum import capability into each BA for estimating available load diversity benefits, we assumed that (1) the available simultaneous import capability would be no larger than the capability of the largest intertie with neighboring BAs and (2) any capacity savings already achieved would be using up some of the import capabilities on the existing lines.[22]

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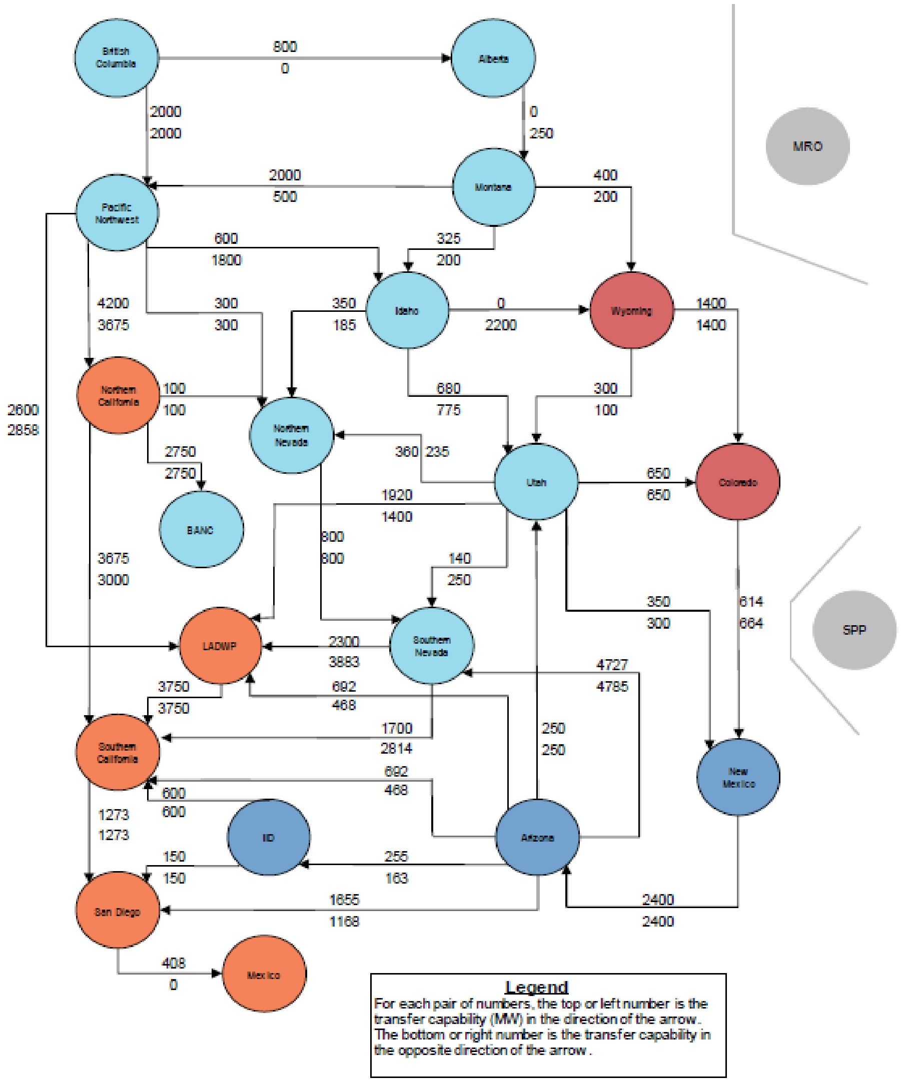
[21] WECC Staff, "Loads and Resources Methods and Assumptions," November 2015, Table 4, Available at: https://www.wecc.biz/ReliabilityAssessment

[22] For several BAs in the Northwest (Avista Corp, Portland General Electric, PUD No 1 of Chelan County, PUD No 1 of Douglas County, Puget Sound Energy Inc., Seattle City Light, Tacoma Power), our estimated within-subregion import capability is *less* than the capacity savings achieved. Because we do not have specific data on transfer capabilities within the Northwest, our estimated import capabilities for these BAs conservatively assume that imports can come only from outside the Northwest. In reality, however, there is substantial transmission capacity in this region and the BAs are likely making use of it. We confirmed this for Puget Sound using its IRP. We assumed that the other BAs could similarly take advantage of transmission within the Northwest.

Figure 2: LAR Zonal Model Summer Transfer Limits



Sources and Notes

WECC Staff, "Loads and Resources Methods and Assumptions," November 2015, Table 4, Available at: https://www.wecc.biz/ReliabilityAssessment.Zone colors correspond to subregions: Orange – California, Light blue – Northwest, Dark blue – Southwest, Red – Rocky Mountain

Finally, we estimated that the avoided cost of capacity savings in 2030 would be $75/kW-yr in California and $100/kW-yr in the rest of the region. The value for California assumes that no new generation will be needed prior to 2030, but that the state will be approaching resource balance and the value of capacity will be increasing. Under such conditions, we would expect the value of capacity to converge to the cost of new entry net of energy and ancillary service margins (*i.e.*, the *net* cost of new entry). The net cost of new entry for a combined-cycle natural gas unit in California has been estimated to be in excess of $150/kW-year.[23] However, we made the conservative assumption that the value of capacity in 2030 is only $75/kW-year based on the conservative assumption of continued (though less severe) excess supply conditions.[24] If additional generating capacity would be needed by 2030 (e.g., due to additional retirements of economically-challenged existing plants), the estimated resource adequacy value of regional load diversity would be double out baseline estimate.

Outside of California, we estimated that the avoided cost of capacity savings in 2030 is $100/kW-year, reflecting the net cost of new entry and the likelihood of new generation needs. Row 17 of Table 2 shows that the net capacity cost savings due to load diversity is $120 million for California and over $260 million for the rest of the region in 2030.

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23 See, for example: http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf

24 This assumes that, other than plants with once-through cooling and Diablo Canyon, no other major existing California generating plant would be retired between now and 2030. Based on feedback by the owners of these generating plants, this is a very (and perhaps unrealistically) conservative assumption because such additional retirements are very likely given the poor existing (and deteriorating future) market conditions faced by these plants.

Table 4: Estimated Generating Capacity Cost Savings from Load Diversity in 2030

All results reported in 2016 dollars

		California	Rest of Region
Capacity Requirement	[1]	115.0-116.1%	75-116.1%
Sum of BA Non-Coincident Peaks (MW)	[2]	57,188	85,302
BA Coincidence Factor (Coincidence with Subregion peak)	[3]	99.2%	94.2%
Sum of BA Peak Loads Coincident with Subregion Peak (MW)	[4]	56,747	80,364
Potential Savings: Sharing Within Subregions (MW)	[5]	508	5,703
Savings Already Captured (Estimated) (MW)	[6]	0	4,481
Incremental Savings w/ Current Transmission: Sharing Within Subregions (MW)	[7]	363	604
Savings Requiring Transmission Upgrades (MW)	[8]	145	618
Effective Coincidence Factor (Coincident **with WECC-PMAs peak)**	[9]	98.1%	96.3%
Estimated Load During WECC Peak (MW)	[10]	55,676	77,415
Potential Savings: Sharing Across Subregions (MW)	[11]	1,231	3,385
Incremental Savings w/ Current Transmission: Sharing Across Subregions (MW)	[12]	1,231	2,060
Savings Requiring Transmission Upgrades (MW)	[13]	0	1,324
Total Savings Requiring Transmission Upgrades (=[8] + [13]) (MW)	[14]	145	1,942
Total Savings w/ Current Transmission (=[7] + [12]) (MW)	[15]	1,594	2,665
Avoided Cost of Capacity Savings ($/kW-yr)	[16]	$75	$100
Total Avoided Cost w/ Current Transmission ($ million/yr)	**[17]**	**$120**	**$266**

Sources and Notes:

[1]: Capacity requirement based on WECC-determined reserve margin levels as reported in 2015 NERC LTRA

[2]: Sum of forecasted BA Non-Coincident Peak Loads in 2030

[3]: Median of 2006-2014 coincidence factors between BA and subregion peaks. Table shows average across BAs in California and Rest of Region, weighted by non-coincident peak loads..

[4]: [2] * [3]

[5]: [1] * ([2] – [4])

[6]: Capacity savings already achieved by BAs based on internal reserve margins

[7]: Savings achievable with current transmission into each BA

[8]: Savings requiring additional transmission based on within-subregion transmission limits in WECC LAR zonal model.

[9]: Median of coincidence factors between subregion and footprint-wide peaks, estimated from hourly BA load data from 2006 to 2014.

[10]: [4] *[9]

[11]: [1] * ([4] – [10]). The ISO savings based on share of Subregion peak load

[12]: Savings achievable with current transmission into each subregion

[13]: Savings requiring additional transmission based on across-subregion transmission limits in WECC LAR zonal model.

[14]: [8] + [13]

[15]: [7] + [12]

[16]: Average avoided cost of new entry for each subregion reflecting $75/kW-yr for California Balancing Authorities and $100/kW-yr for non-California Balancing Authorities.

[17]: [15] * [16]

G. Sensitivity: Generating Capacity Cost Savings from Load Diversity in 2020 With an Expanded Regional ISO Footprint

Our baseline assumes that in 2020, the regional market will be limited to the ISO and PacifiCorp. However, we evaluated capacity savings for a sensitivity case where all of the U.S. WECC (except the PMAs) participates. In this 2020 Regional sensitivity case, we applied the same methodology as in our 2030 analysis, using historical coincidence factors to estimate the savings associated with load diversity. As with our 2030 analysis, we estimated capacity savings in this sensitivity case in two steps: savings from capacity sharing *within* WECC subregions and savings from capacity savings *between* WECC subregions. We accounted for capacity savings achieved by utilities and for transmission limitations in the same manner as in our 2030 analysis. For the purposes of the sensitivity, we used a lower avoided cost of capacity savings of $35/kW-year, reflecting the 2012–2016 weighted average resource adequacy contract price in California and the upper end of the zero to $37/kW-year range that was used for PacifiCorp.

As expected, the 2020 regional sensitivity results show that a larger regional footprint in 2020 provides additional benefits for California, but not as much as could be achieved in 2030. Savings are higher compared to the 2020 baseline scenario for two reasons: 1) adding LADWP, BANC, TIDC, and IID to the market region increases the participating load in California and 2) including most of the WECC in the regional market increases the potential for load diversity. Savings are lower compared to the 2030 baseline due to two offsetting factors. First, the MW savings are higher in the 2020 regional sensitivity because 2020 load is higher than 2030 load due to high energy efficiency targets, which result in negative projected load growth. However, the higher MW savings are offset by lower avoided costs assumed in 2020 ($35/kW-year in 2020 vs. the $75/kW-year baseline in 2030) in California. This yields estimated 2020 savings of $58 million/year for California and $84 million/year for the rest of the region.

Table 5: Estimated Generating Capacity Cost Savings from Load Diversity in the 2020 Regional Sensitivity

All Results Reported in 2016 dollars

		California	Rest of Region
Capacity Requirement	[1]	115-116.1%	75-116.1%
Sum of BA Non-Coincident Peaks (MW)	[2]	59,688	75,829
BA Coincidence Factor (Coincidence with subregion peak)	[3]	99.3%	94.0%
Sum of BA Peak Loads Coincident with Subregion Peak (MW)	[4]	59,262	71,295
Potential Savings: Sharing Within Subregions (MW)	[5]	491	5,236
Savings Already Captured (Estimated) (MW)	[6]	–	4,136
Incremental Savings w/ Current Transmission: Sharing Within Subregions (MW)	[7]	353	533
Savings Requiring Transmission Upgrades (MW)	[8]	138	567
Effective Coincidence Factor (Coincident with WECC-PMAs peak)	[9]	98.1%	99.8%
Estimated Load During WECC Peak (MW)	[10]	58,129	68,689
Potential Savings: Sharing Across Subregions (MW)	[11]	1,304	2,991
Incremental Savings w/ Current Transmission: Sharing Across Subregions (MW)	[12]	1,304	1,856
Savings Requiring Transmission Upgrades (MW)	[13]	–	1,135
Total Savings Requiring Transmission Upgrades (=[8] + [13]) (MW)	[14]	138	1,702
Total Savings w/Current Transmission (=[7] + [12]) (MW)	[15]	1,657	2,388
Avoided Cost of Capacity Savings ($/kW-yr)	[16]	$35	$35
Total Avoided Cost w/Current Transmission ($ million/yr)	[17]	$58	$84

Sources and Notes:

[1]: Capacity requirement based on WECC-determined reserve margin levels as reported in 2015 NERC LTRA

[2]: Sum of forecast BA Non-Coincident Peak Loads in 2020

[3]: Median of 2006-2014 coincidence factors between BA and subregion peaks. Table shows average across BAs in California and Rest of Region, weighted by non-coincident peak loads. It is slightly different than the 2030 value because non-coincident peak loads are slightly different in 2020.

[4]: [2] * [3]

[5]: [1] * ([2] – [4])

[6]: Capacity savings already achieved by BAs based on internal reserve margins

[7]: Savings achievable with current transmission into each BA

[8]: Savings requiring additional transmission based on within-subregion transmission limits in WECC LAR zonal model.

[9]: Median of coincidence factors between subregion and footprint-wide peaks, estimated from hourly BA load data from 2006 to 2014.

[10]: [4] *[9]

[11]: [1] * ([4] – [10]). The ISO savings based on share of Subregion peak load

[12]: Savings achievable with current transmission into each subregion

[13]: Savings requiring additional transmission based on across-subregion transmission limits in WECC LAR zonal model.

[14]: [8] + [13]

[15]: [7] + [12]

[16]: Assumed avoided cost of $35/kW-yr for California and Rest of Region in the 2020 Regional scenario

[17]: [15] * [16]

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