Integration and Optimization of Distributed Energy Resources: Big Data Analytics do the Job

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Introduction

This paper presents methods and data to reduce overall costs and substantially increase efficiencies with locational configuration of distributed energy resources (DERs). The electric industry faces unprecedented change as DER costs decline and efficiencies improve. With increased deployment of smart grid infrastructure, consumers' further engage, benefits expand, energy awareness grows, and regulatory policy supports DERs. Several regional planning areas have recently identified the need for distribution level integrated planning, combining cost effective capital investment with programs and services that lower the overall cost of delivering energy while maintaining reliability and security[1]. Recent studies including those by EISPC[2] and NARUC[3] have focused on state-of-the-art concepts and tools that offer more granular analytics to better define the benefits of these resources on the distribution and bulk grid systems.

Together, these studies recognize the importance of aligning programs and technologies with consumer preferences and utility costs[4]. In this paper we test the potential to optimize program performance, target consumer preferences, and minimize locational utility costs, to achieve integrated system level planning. Overall, this paper provides a methodology, steps, and results, to integrate and optimize DERs, lower overall costs, and increase customer acceptance. The focus is on use of "big data" sources to provide advanced analytics. Advanced planning data, smart meters, customer demographics, SCADA data, and market data accordingly leverage DER integration and optimization.

The study uses several large data sources and provides an example of "big data" analytics. Specific focus points are on smart meter and customer demographics through the SCADA and markets, as drivers of energy, capacity, and distribution system costs. Our results indicate that the integration of energy efficiency with the locational benefits of solar and other distributed resources can improve the cost effectiveness and consumer acceptance by aligning consumer preferences with utility costs. The approach enables truly innovative program results. By identifying sub-regions that require significant infrastructure investments, we find improvements in utility benefits by over a 2x, a 28% improvement in overall program cost-effectiveness, and greater achievable potential through locational targeting of energy efficiency and solar programs. Improved cost-effectiveness is achieved by targeting customers in

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[1] For example, the California PUC recently required all IOU's to submit DRP's detailing the circuit level impacts of DER on the distribution system.
[2] EISPC, Eastern Interconnection States' Planning Council
[3] NARUC, National Association of Regulatory Utility Commissioners
[4] LoadSEER (Load Spatial Electric Expansion & Risk) is a spatial load forecasting system designed specifically for utility planners who face increasingly complex grid decisions caused by emerging micro-grid technologies, extreme weather events and new economic activity.

high cost of service sub-regions, including areas with older equipment that can benefit from life extension and customers who benefit from specific programs.

Our approach targets consumer preferences and locational utility costs with use of an optimal net metering charge for community solar. CPS Energy has demonstrated the integration of energy efficiency with the locational benefits of solar and other distributed resources to dramatically improve cost effectiveness, increase consumer acceptance, and lower utility costs. Through targeting, overall net metering charges can be best aligned with the needs of the utility and the preferences of customers. In summary, these results show just how big data analytics can effectively integrate and optimize DERs and the grid.

Methodology

Historically, DSM planners and integrated resource planners have focused only on bulk-grid benefits across generation and (high voltage) transmission. The standard benefits described in the California Standard Practice Manual ratios for cost effectiveness reflect this bias. Avoided costs used in these tests have been limited to the cost of energy and ancillary services, avoided capital cost of generation, the avoided capital cost of transmission, and in some jurisdictions a societal costs for carbon emissions.

This approach, however, completely misses the localized benefits from reducing the costs of transmission to the substation and further down to the meter. These are the costs typically identified by distribution system planners. For example, the 1547 IEEE Standard for Interconnecting Distribution Resources with Electric Power Systems[5] specifies several cost categories not mentioned by the traditional cost-effectiveness, or grid level planning models. These include distribution capacity, the ability to manage voltage fluctuations, inadvertent energization, serge protection, active voltage regulation, frequency modulation, volt-ampere reactive (var) support, power factor, backflow, protection, and other costs.

Correctly identifying the impacts of DER on distribution level avoided cost measure leads to optimal placement, higher reliability, and reduced cost to serve customers. In the example shown below, circuit level over-voltage costs are identified by location, time of day, and magnitude, leading to an optimal DER deployment schedule for the planning engineer.

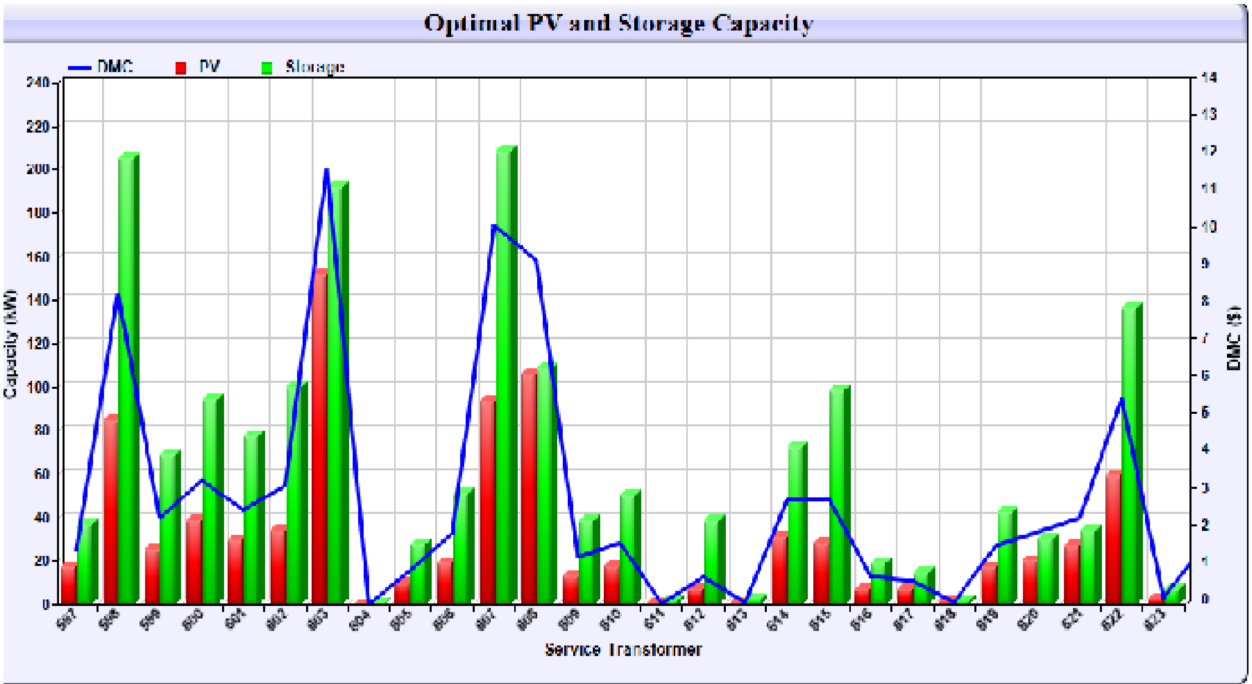
[5] IEEE Standards Coordinating Committee 21, 1547 – 2003.

LoadSEER Power flow Leads DER Optimization
(Red = Overvoltage)

Local distribution level costs can only be identified by using granular, local measures of avoided cost. However, the temptation at this point would be to adopt a deterministic, ex ante, average circuit cost approach, which is used in many places like California. This averaging approach leads to a significant undervaluation of the actual costs and of the benefits with focused use of DER.

As alternative technologies including photovoltaic and storage become increasingly cost effective, optimal deployment plans will become increasingly needed. In the example below, we define optimal PV and storage Locations, and the magnitude of each deployment, for a bank of secondary transformers across three circuits. The blue line represents the local cost of service.[6] The optimal amounts of PV and storage are shown by the red and green bars respectively. The optimal solution is based on lowering the cost of service. In this case the storage capacity may exceed the capacity of the PV system. Optimal PV and Storage locations, magnitudes and value are identified over the planning horizon. This more detailed level of analysis is only possible using actual granular data and granular analysis hierarchies, consistency with proven methods and probabilistic risk analysis based on actual load history, weather data and prices.

[6] Measuring the cost of service locally, through the distribution system from the substation to the secondary transformer generates a locational marginal price, described here as a distribution marginal cost (DMC).



In this example, the optimal deployment of the PV and storage resources is based on the cost of service, which include the unique characteristics of the circuit. In a recent EPRI report, the overall benefits of distributed energy resources (DER's) are characterized and used to optimally measure hosting capacity.[7]

As shown in the chart above, some circuits can host a large amount of DER, others not so much. Consistent with the EPRI framework, several core analytical elements are used to fully measure the integrated benefits of DER. First, an accurate spatial forecast of energy demand is performed by class. Second, DER adoption and other expected system changes are identified to quantify the impacts of DER on the distribution and bulk power systems. Third, the analysis includes an assessment of hosting capacity based on the level of DER interconnection that can be locally accommodated without impacting the quality of supply from existing infrastructure. Several components of avoided cost are required to optimally site DER. Such analysis considers energy, capacity, reliability costs, and protection related costs both at the distribution level -- from the substation to the meter and the bulk power level – and from the substation to the generator.

Cost and benefits are processed to reflect standard regulatory cost-effectiveness results. In the table below, the cost-effectiveness of a PV and Storage deployment across a distribution bank is calculated. The full set of benefits and costs are identified from the perspective of the utility and the participant.

[7] The Integrated Grid, A Benefit-Cost Framework, EPRI, 3002004878, Final Report, February 2015.

Using Distributed Marginal Costs for Bank A231

Bank A231: 1,400 Service Transformers		**Daily Variability in Avoided Cost Value**				**10 Year**
		Low	Average	High		**NPV**
Utility Benefits						
	Revenue from power sold	$128,649	$178,838	$347,561		$74,758,758
	Avoided cost	$118,800	$263,072	$981,060		$141,918,604
Utility Costs						
	Cost of power from grid	$80,739	$147,837	$354,276		$65,107,739
	Cost of purchased power (PV&Storage)	$2,929	$7,615	$40,967		$5,072,684
Total Utility net benefits		$161,429	$274,924	$839,372		$136,423,493
Customer Benefits						
	Avoided purchased power	$185,544	$280,841	$606,547		$120,939,738
	Power from PV/Storage sold to grid	$2,929	$7,615	$40,967		$5,072,684
Customer Costs						
	Purchased power from grid	$128,649	$178,838	$347,561		$74,758,758
	PV cost	$48,178	$74,171	$181,194		$33,554,882
	Storage cost	$78,721	$153,187	$339,350		$64,849,098
Total Customer net benefits		($67,077)	($117,741)	($220,591)		($47,150,317)
Total Benefits		$434,746	$724,599	$1,929,132		$337,653,060
Total Costs		$340,393	$567,416	$1,310,351		$248,379,884
Net Benefit		**$94,352**	**$157,183**	**$618,781**		**$89,273,176**
			Total Resource Cost Test (10 Yr NPV)			**1.36**

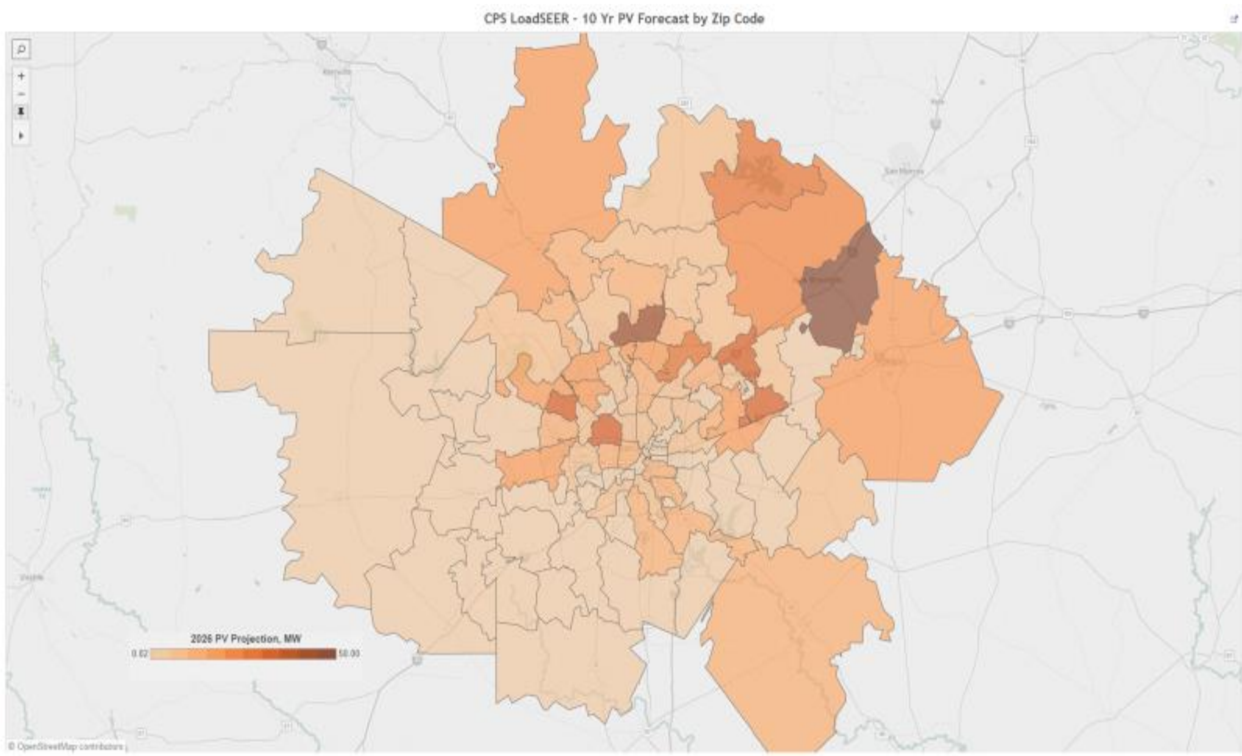
These results indicate that the program is not economic from the perspective of the participant alone. However, from the perspective of the utility, the program benefits significantly exceeds program costs. The overall cost-effectiveness ratio is 1.36. In this case the utility benefits can be used to offset the cost of the technology through optimal incentive structures.

Overall Results

The overall results focus on integration of successful solar projects with energy efficiency program goals and targets. Specifically, the locational interaction of projects is shown to provide significant benefits to the overall program cost effectiveness and improve the overall potential of alternative distributed energy investments. Program design results increasingly become central to the overall utility planning process as locational information is used to expand the role of demand side projects that alleviate locational grid costs and improve reliability.

Load and DER Adoption Forecast

Integral Analytics gathered data from several public sources to map the future adoption of rooftop photovoltaics and other DER's at the zip code level. It then developed an adoption model based on U.S. Census demographic variables to predict adoption of these resources at the zip code level. We then applied the regression model coefficients to all zip codes in the U.S. Additionally, we applied a score for Wind Resource Potential using the National Renewable Energy Laboratory's (NREL) Wind Map. These zip code scores were then mapped against U.S. Energy Information Administration (EIA) projections of Distributed Energy Resource adoption (DERs - ie EVs, Solar, and Wind) on a 10-year timeline. In addition to DER adoption, using EIA data we calculated several metrics to assess regional capacity and grid constraints. We calculated a Capacity Margin based on projected peak loads compared to projected generation capacity, from which we calculated a levelized regional Capacity Cost ($/kW). Integral Analytics then applied a weighted matrix that combined the interaction of these metrics into one summary statistic to derive an overall ranking. In the map below, the locational rank indicates areas in the service territory which are likely to see increased solar adoption at the zip code level. At this higher resolution, we identify specific distribution assets that may see increased adoption of DERs and identify potential capacity constraints.



Optimal Deployment of Solar Technologies

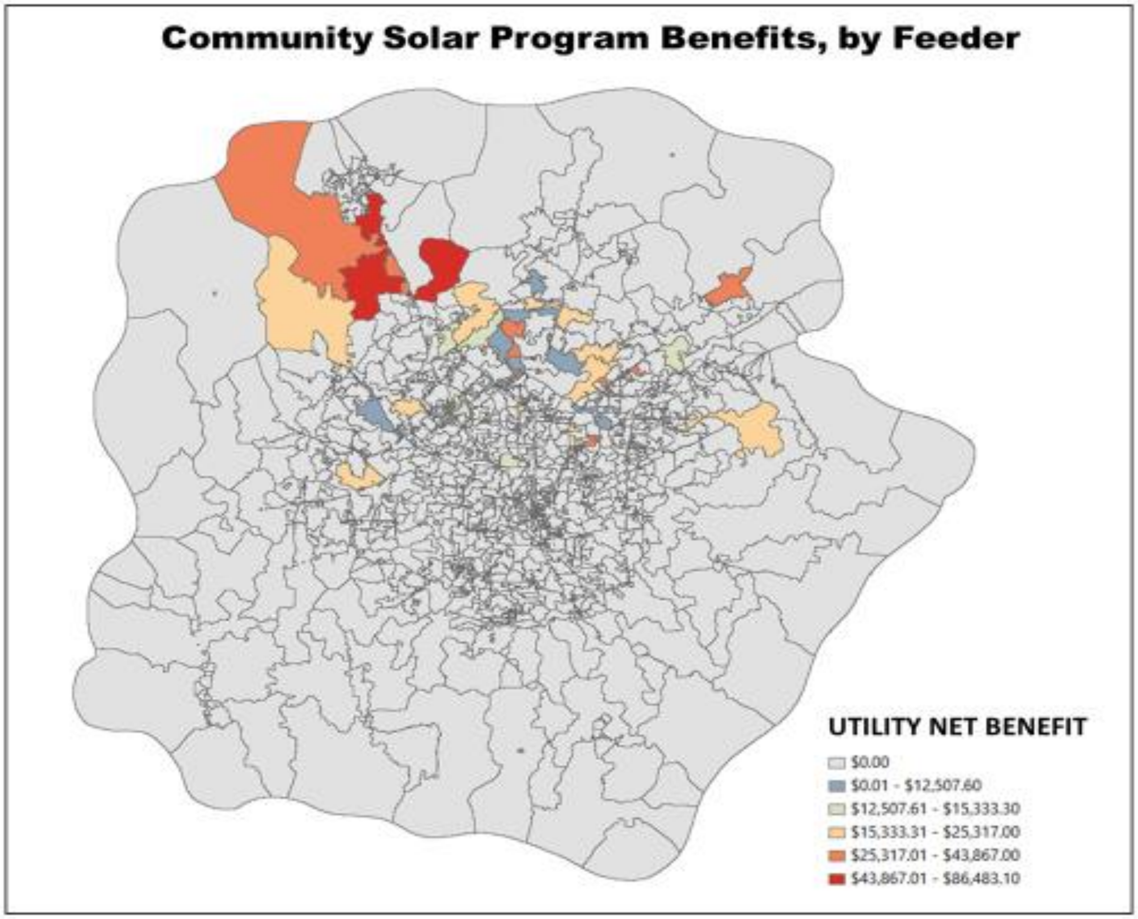
Information from the load and adoption forecast can be used by the utility planners to optimize capital budgets and optimize utility services. Utility data is used to determine the specific Capacity Margin at each feeder, bank (substation) and distribution planning area, consistent with overall utility growth projections. This information determines the baseline by which any DER program can be compared.

Specifically in this paper we measure the cost effectiveness of two stylized utility solar programs – a residential Community Solar program and a Commercial Rooftop Solar program. The load forecast and planned capacity upgrades are used to project the specific feeder Capacity Margin through the life of project. The program impacts are determined at the feeder level by measuring the program impact on the feeder load shape through the life of the program.

Community Solar results are summarized in the table below. Program benefits and costs are shown from both the utility and the participant perspectives. Two targeting strategies are compared to the system average results. Using the system average approach, the program is expected to return over $3 million to the utility (discounted through the life of the program). This equates to a 1.26 UTC cost effectiveness ratio. However, if the same program were designed to target the feeders experiencing low Capacity Margin the expected return to the utility exceeds $6 million, more than a 2x increase. The UTC ratio increases 21% to 1.53. The program is designed to assure that the participant maintains a participant cost-benefit ratio greater than 1. However, from the demographic study "free rider" participants can be identified who are willing to be early adopters of the technologies. These participants are willing to contribute a greater share of the overall cost. In the example below, participant targeting when added to Capacity Margin targeting raises the overall utility revenue to over $6.7 million equating to a UTC ratio of 1.61.

Community Solar Cumulative	System Average	Targeted by Feeder	Targeted by Feeder And Customer Willingness to Pay
Program Details: 25 Year PV Measure Life, 7.6kW Capacity, 921 Residential Installations over 5 Years			
Utility Benefits			
Avoided Electric Production	$ 7,468,981	$ 7,492,881	$ 7,492,881
Avoided Electric Capacity	$ 4,814,500	$ 4,829,906	$ 4,829,906
Avoided T&D Electric	$ 3,066,170	$ 6,039,057	$ 5,435,151
Utility Costs			
Implementation / Participation Costs	$ 845,817	$ 640,920	$ 761,235
Incentives	$ 11,362,141	$ 11,398,500	$ 10,258,650
Total Utility Net Benefits	$ 3,141,692	$ 6,322,425	$ 6,738,054
Utility Cost Test (25 Yr. NPV)	1.26	1.53	1.61
X Times Increase in Net Utility Benefits		2.01	2.14
% Increase in the UTC Ratio		21%	28%
Customer Benefits			
Bill Savings (Electric) (Gross)	$ 7,074,729	$ 7,097,368	$ 7,097,368
Incentives	$ 11,362,141	$ 11,398,500	$ 10,258,650
Customer Costs			
Participant or Unit Costs (Gross)	$ 18,326,034	$ 18,384,677	$ 19,524,527
Net Benefits	$ 110,836	$ 111,190	$ (2,168,510)
Participant Cost Ratio (PAC)	$ 1.01	$ 1.01	$ 0.89
Annual Payback	$ 282,989.14	$ 283,895	$ 283,895
Years	24.6	24.6	32.6

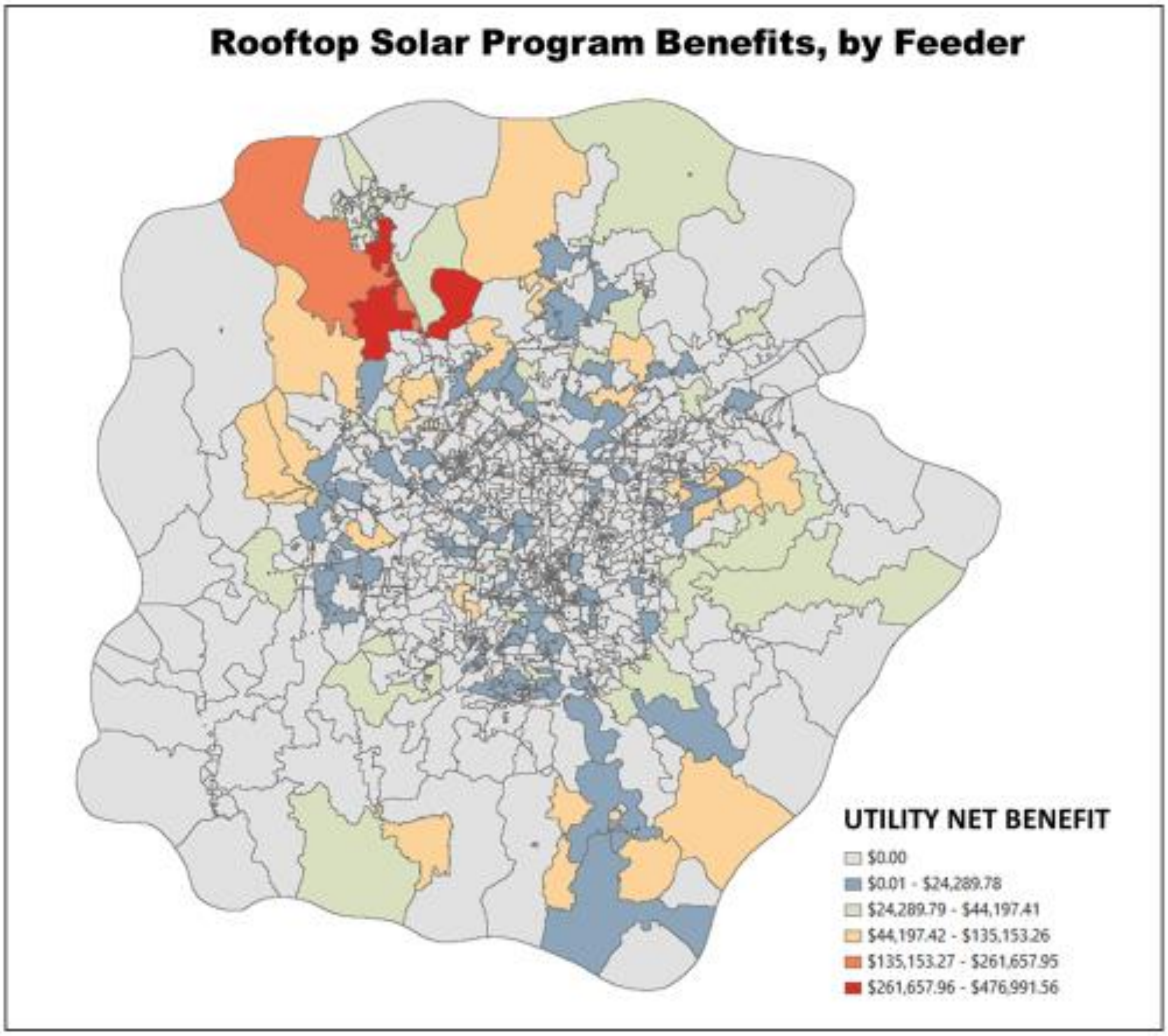
The map below spatially identifies the targeted feeders. The map is color coded by the total utility benefit for separate feeders.



The Rooftop Solar results are summarized in the table below. Program benefits and costs are shown from both the perspective of the utility and the participant. Two targeting strategies are compared to the system average results. Using the system average approach, the program is expected to return over $400k to the utility (discounted through the life of the program). This equates to a 1.17 UTC cost effectiveness ratio. However, if the same program were designed to target the feeders experiencing low Capacity Margin the expected return to the utility exceeds $900k, a 2.4x increase. The UTC ratio increases 21% to 1.42. The program is designed to assure that the participant maintains a participant cost-benefit ratio greater than 1. From the demographic study "free rider" participants can be identified who are willing to adopt the technologies early. These participants are willing to contribute a greater share of the overall cost. In the example below, participant targeting when added to Capacity Margin targeting raises the overall utility revenue to over $1 million equating to a UTC ratio of 1.50.

Roof Top solar PPA Cumulative	System Average	Targeted by Feeder	Targeted by Feeder And Customer Willingness to Pay
Program Details: 25 Year PV Measure Life, 7.6kW Capacity, 31 Commercial Year 1 Installations			
Utility Benefits			
Avoided Electric Production	$ 1,283,568	$ 1,302,238	$ 1,302,238
Avoided Electric Capacity	$ 923,717	$ 937,153	$ 937,153
Avoided T&D Electric	$ 588,280	$ 1,140,678	$ 1,026,610
Utility Costs			
Implementation / Participation Costs	$ 165,000	$ 137,860	$ 148,500
Incentives	$ 2,216,500	$ 2,248,740	$ 2,023,866
Total Utility Net Benefits	$ 414,065	$ 993,469	$ 1,093,635
Utility Cost Test (25 Yr. NPV)	1.17	1.42	1.50
X Times Increase in Net Utility Benefits		2.40	2.64
% Increase in the UTC Ratio		21%	28%
Customer Benefits			
Bill Savings (Electric) (Gross)	$ 1,379,934	$ 1,400,006	$ 1,400,006
Incentives	$ 2,216,500	$ 2,248,740	$ 2,023,866
Customer Costs			
Participant or Unit Costs (Gross)	$ 3,575,000	$ 3,627,000	$ 3,851,874
Net Benefits	$ 21,434	$ 21,746	$ (428,002)
Participant Cost Ratio (PAC)	$ 1.01	$ 1.01	$ 0.89
Annual Payback	$ 55,197	$ 56,000	$ 56,000
Years	24.6	24.6	32.6

The map below spatially identifies the targeted feeders. The map is color coded by the total utility benefit, for each feeder.

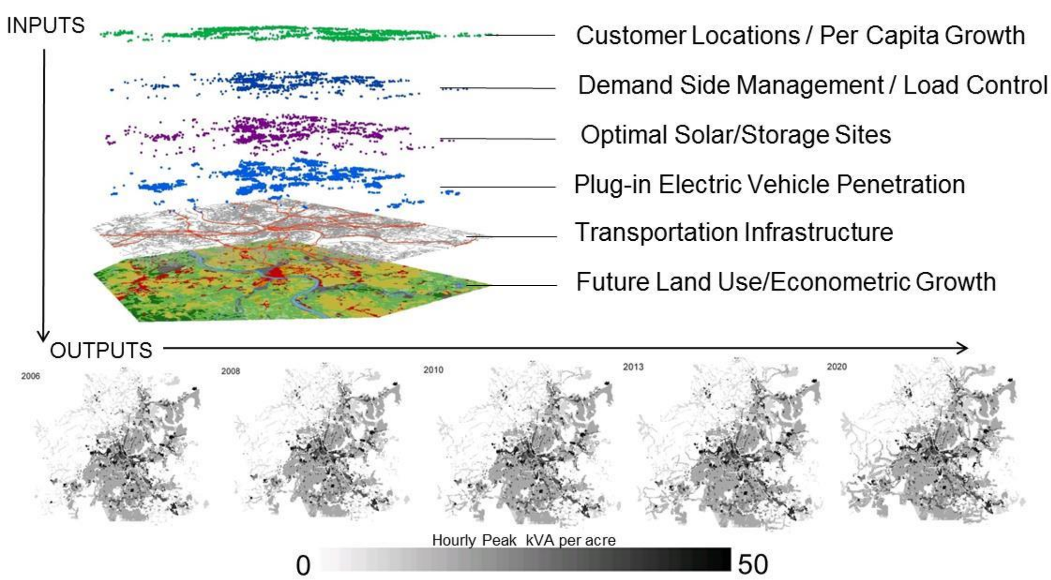


Conclusion

Advanced analytics, enabled by big data, dramatically change the landscape for DERs. By identifying sub-regions of the CPS Energy system that require significant infrastructure investments, we find over 2x improvement in utility benefits and a 28% improvement to overall program cost-effectiveness. These benefits are achievable through locational targeting of energy efficiency and solar programs. Improved cost-effectiveness is achieved by targeting customers in high cost of service sub-regions, including areas with older equipment that can benefit from life extension and customers who benefit from specific programs. The results demonstrate significant improvement in program effectiveness and value through locational distribution level targeting of actual specific capital investments and customers, by program, location and time. Actual results indicate that significant improvement is possible in reliability, lower cost of service and more efficient use of the system installed capital.

Appendix – The Best in Class DER Planning Software

Integral Analytics planning and evaluation software is currently used by dozens of utilities in over 40 states. LoadSEER (Spatial Electric Expansion & Risk) is a spatial load forecasting software tool designed specifically for transmission and distribution (T&D) planners who face increasingly complex grid decisions caused by emerging microgrid technologies, extreme weather events, and new economic activity. The objective of LoadSEER is to statistically represent the geographic, economic, distributed resources, and weather diversity across a utility's service territory, and use that information to forecast circuit and bank level peak loads, sub-sections of the circuit, acre-level changes, and impacts from various scenarios over the planning horizon. Planners are able to decompose system impacts using map layers superimposed on the spatial representation of the T&D infrastructure. As shown in the following figure, load growth forecasts, distributed renewable generation, demand response, distributed intelligent systems, and other demand or supply factors are spatially located relative to the existing capital infrastructure.



LoadSEER's powerful GIS mapping and load forecasting functionality uniquely blends traditional peak load regression based forecasting with more sophisticated econometric forecasting and rigorous geospatial forecasting. Multiple methods lead to increased confidence in the final forecast. This enables distribution planners to more accurately predict risks on their circuits due to local load growth and/or distributed generation changes, including electric vehicle adoption, increasing solar penetration, switching transfers, demand response, and other factors. The core algorithms automatically model geographic and economic drivers, along with weather, to provide engineers with the most representative circuit by circuit forecast models. In some cases, one circuit might respond to retail sales, while another might be sensitive to employment, personal income, housing starts, or various combinations.

This process enables planners to analyze specific future scenarios such as transportation network expansion, suburban sprawl, urban redevelopment, new manufacturing, and additional employment centers. The final forecast results can be leveraged to enhance an existing suite of planning tools, including direct exports to power flow analysis tools, used in forecasting future transmission congestion, calculation of local avoided costs for optimal DER integration, and Distribution IRP requirements.

LoadSEER insures both short and long term consistency with system level financial planning, by streamlining regulatory data requirements, creating more defensible long term substation forecasting methods, and streamlining various aspects of the decision and approval process. Moreover, the software enables a much more accurate methodology for calculating avoided marginal costs of grid asset deferrals for use in more intelligently targeting DG, Smart Grid programs, and demand response and energy efficiency.

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