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CIGRE US National Committee
2021 Grid of the Future Symposium

Customer Choice: The Paradigm Shift and Future Potential of Customer Owned Distributed Energy Resources (DERs)

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SUMMARY

There are significant opportunities to provide customer and utility value by 1) implementing grid-edge distributed energy projects in coordination with 2) grid level balancing and contingency operations, including reducing energy delivery costs and customer bills, and improving reliability while avoiding costly infrastructure development projects. These benefits can be achieved through the development and implementation of *Distribution Level System Operation*[1] in which the optimal dispatch of DER's and supply-side resources is determined based on customer preferences and utility needs.

In this study, we simulate a service territory of approximately 8 to 12 million electric customers. We simulate dynamic distributed resource management (e.g. Distribution Level System Control). Distribution level control includes technologies that enable third-party control over customer load, possibly impacting costs and quality of service (i.e. Alexa, NEST, etc.). The benefits/risks from this new capability are not understood. The project's goal was to reasonably estimate potential impacts to:

- Utility costs (avoided energy, capacity, and T&D costs)
- Load profile (kW, kWh) by customer class (residential, commercial, industrial)
- Customer satisfaction

The emphasis of this study is to identify **technical and economic potential** – by class then system total, limited by grid characteristics and cost-effectiveness (targeted IDSM – geographic and demographic).

KEYWORDS

Integrated Demand Response, Distributed Energy Resources, Customer Choice

[1] Distribution Level System Control for the purpose of this report includes remote sensing, metering and active intelligence. Active intelligence refers to system balancing, switching or control capabilities resulting from distributed data sources and optimizations constrained by customer energy needs, utility sales goals, system power quality or reliability and/or other constraining factors such as customer satisfaction.

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INTRODUCTION

In this study, we simulate a service territory of approximately 8 to 12 million electric customers. The project provides the building blocks to determine how to hedge or expand customer centric energy services based on emerging technologies and capabilities. Specifically, in this project algorithms are tested to demonstrate:

1) That uncontrolled price arbitrage (by third party aggregators) can lead to new peaks. We demonstrate how distributed utility (DSO) control can manage these peaks. The application is similar to the EV charging problem – to incentivize customers to charge at night, rather than in the afternoon when they return home from work.
2) With respect to managing peak load from price arbitrage, demand charges are added to the optimization (in addition to delivery cost minimization), representing potential tariff or utility pricing mechanisms needed to control peak creation from price following activity.
3) Peak load reduction is analyzed through the Willdan/Integral Analytics LoadSEER™, by identifying both the expected reduction in the need for capital expansion over time and risk of unexpected overloading due to extreme events, focused on circuit growth over the study horizon.

The emphasis of this study is to identify **technical and economic potential** – by class then total, limited by grid characteristics and cost effectiveness (targeted IDSM – geographic and demographic). Optimization model estimates of system coincident peak load reductions for each customer class at three selected customer efficiency levels are show in the table below.

DEC DR Technical Potential							
	Collective Model kW			Technical Potential	Constrained Technical Potential	Constrained Technical Potential	Constrained Technical Potential
Class / Category	5%	50%	95%	kW	MW 50 Percentile	MW 5 Percentile	MW 95 Percentile
Residential	0.32	0.73	1.47	1,530,880	1,531	677	3,065
Commercial				810,530	811	708	962
Industrial				550,097	550	338	685
Total					2,892	1,723	4,712

Key Takeaway: Technical Potential for constrained optimization is approximately 2,900 MW. Targeting less efficient customers has significant upside.

The assessment of economic potential involves two major sets of analyses.

1) The use of Integral Analytics LoadSEER™ software to prepare spatial forecasts of load at the distribution substation level. The application of this model enables identification of those areas of the service area that are expected to require transmission and/or distribution system upgrades in the near future. Those are the areas that will provide higher avoided costs (benefits) that can improve the cost-effectiveness of the load reduction program implementation.[2]

[2] LoadSEER (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.
In this project, LoadSEER was used to statistically represent the geographic, economic and weather diversity across the Duke Energy Carolinas (DEC) service territory, and to create a forecast of regional peak loads over the planning horizon.

2) The use of Integral Analytics DSMore™ software to perform the avoided cost valuations associated with investments in the load reduction program.

Results and Key Takeaways

The results and key takeaways are shown below.

Key Takeaway: Spatial T&D system analysis and planning (i.e. LoadSEER) can be used to identify areas with potential reliability risk given projected load growth and capacity utilization. Risks are mitigated through distributed optimization technologies.

Using the projected loads for each service area, the capacity of each service area can be checked to assess when the load growth could be creating a reliability risk. The assessment occurred at two levels for loads and distribution capacity.

- First, peak loads were examined at a normal level (50% level) and at an extreme level (90% level) using the analysis of load research data previously discussed. The 90% level represents a 1 in 10 year level of occurrence.
- And second, the distribution system capacity was computed at a normal level and at a maximum level.

The service territory planning areas were placed into five categories according to the following definitions:

- Those needing additional capacity – loads today at the 50% level exceed the normal capacity and loads at the 90% level exceed 90% utilization of the max capacity
- Those needing additional capacity by 2020 (5 years) – loads in 2020 at the 50% level exceed 90% of the capacity utilization at normal capacity and loads at the 90% level exceed 90% capacity utilization at max capacity
- Those needing additional capacity by 2025 (10 years) – loads in 2025 at the 50% level exceed 80% of the capacity utilization at normal capacity and loads at the 90% level exceed 80% capacity utilization at max capacity
- Those needing additional capacity by 2030 (15 years) – loads in 2030 at the 50% level exceed 50% of the capacity utilization at normal capacity and loads at the 90% level exceed 50% capacity utilization at max capacity
- Those not needing additional capacity by 2030 – loads at the 90% level never exceed 50% of the max capacity utilization

The results of the spatial assessment of capacity utilization are shown in the following chart. Red areas face the highest projected capacity utilization.

Key Takeaway: Areas with high capacity utilization can be targeted first for deployment of distributed optimization.

Cost Effectiveness Results

DSMore was used to estimate the economic potential associated with the application of a distributed optimization engine approach to managing customer loads. DSMore allows one to estimate the benefits in terms of avoided costs achieved through the optimization of customer loads. The optimization of the customer loads enables the opportunity to delay capital equipment investment as well as extend the life of existing assets. The estimated avoided costs represent the value created that can be compared to the costs to implement the optimization approach.

DSMore was used to develop the total capacity avoided costs (generating capacity plus transmission and distribution (T&D) capacity costs). For the T&D avoided capacity costs, two levels were examined.

- Avoided T&D costs including investment spending on smart grid capabilities. This is referred to as the High T&D avoided cost scenario in the results.
- Avoided T&D costs, excluding investment spending on smart grid capabilities. This is referred to as the Base T&D avoided cost scenario in the results.

In addition, multiple levels of costs were developed using the historical distribution of the Companies T&D costs per kW-year. Eleven (11) levels were established centered on the medium value for both the High and Base T&D avoided cost estimates.

Additional scenarios were evaluated as follows:

- Since details on the equipment cost and life were not available, the model was run using three levels of equipment life, 5 years, 10 years, and 15 years.
- To capture differences in customer efficiency, three (3) levels were studied: high – 5th percentile, medium -50th percentile, and low – 95th percentile.
- Avoided cost estimates were prepared for each of the thirteen customer types
- The combination of customer types, T&D avoided costs, equipment lives, and customer efficiency levels produces two sets of 1,287 DSMore™ analyses.
- The avoided cost values represent the amount that can be spent on program implementation for each of the specific scenarios.

Scenarios			
Number	Timing	T&D Avoided Cost	Customer Energy Efficiency
1	All service areas: no timing	Base: $20.29	Medium
2	All service areas: no timing	Base: $35.90	Medium
3	All service areas: no timing	Base: $51.52	Medium
4	All service areas: no timing	Base: $20.29	Low
5	All service areas: no timing	Base: $35.90	Low
6	All service areas: no timing	Base: $51.52	Low
7	All service areas: no timing	High: $40.66	Medium
8	All service areas: no timing	High: $74.30	Medium
9	All service areas: no timing	High: $107.93	Medium
10	All service areas: no timing	High: $40.66	Low
11	All service areas: no timing	High: $74.30	Low
12	All service areas: no timing	High: $107.93	Low
13	Upgrades timed	Base	Medium
14	Upgrades timed	Base	Low
15	Upgrades timed	High	Medium
16	Upgrades timed	High	Low

The results of the cost effectiveness analysis are shown in the following table. First twelve scenarios assume total retail service area. Last four reflect valuations under a timed or staged implementation.

Avoided Costs for All Scenarios: Capacity Value for Generation, Transmission and Distribution						
Number	Timing	T&D Avoided Cost	Customer Energy Efficiency	Distribution	Transmission	Total
1	All service areas: no timing	Base: $20.29	Medium	$ 4,138,997,766	$ 553,163,385	$ 4,692,161,151
2	All service areas: no timing	Base: $35.90	Medium	$ 4,936,628,400	$ 659,764,086	$ 5,596,392,486
3	All service areas: no timing	Base: $51.52	Medium	$ 5,734,259,035	$ 766,364,786	$ 6,500,623,821
4	All service areas: no timing	Base: $20.29	Low	$ 5,964,767,472	$ 876,081,417	$ 6,840,848,889
5	All service areas: no timing	Base: $35.90	Low	$ 7,114,244,116	$ 1,044,911,993	$ 8,159,156,109
6	All service areas: no timing	Base: $51.52	Low	$ 8,263,720,759	$ 1,213,742,569	$ 9,477,463,329
7	All service areas: no timing	High: $40.66	Medium	$ 5,179,363,790	$ 692,204,869	$ 5,871,568,659
8	All service areas: no timing	High: $74.30	Medium	$ 6,897,664,432	$ 921,850,076	$ 7,819,514,509
9	All service areas: no timing	High: $107.93	Medium	$ 8,615,965,075	$ 1,151,495,284	$ 9,767,460,359
10	All service areas: no timing	High: $40.66	Low	$ 7,464,053,475	$ 1,096,290,606	$ 8,560,344,081
11	All service areas: no timing	High: $74.30	Low	$ 9,933,375,089	$ 1,459,994,900	$ 11,393,369,989
12	All service areas: no timing	High: $107.93	Low	$ 12,407,911,936	$ 1,823,699,195	$ 14,231,611,131
13	Upgrades timed	Base	Medium	$ 4,042,013,690	$ 766,364,786	$ 4,808,378,477
14	Upgrades timed	Base	Low	$ 5,791,602,200	$ 1,213,742,569	$ 7,005,344,769
15	Upgrades timed	High	Medium	$ 5,497,546,122	$ 1,151,495,284	$ 6,649,041,406
16	Upgrades timed	High	Low	$ 7,884,142,613	$ 1,823,699,195	$ 9,707,841,808

Key Takeaway: Considerable value found. Lowest value is above $4 B.

Per customer valuations reflect the avoided costs available to offset implementation costs. These are shown in the following table.

Avoided Cost Per Customer: Capacity Value for Generation, Transmission, and Distribution							
				Distribution			
Number	Timing	T&D Avoided Cost	Customer Energy Efficiency	Residential	Commercial	Industrial	Transmission
1	All service areas: no timing	Base: $20.29	Medium	$ 552	$ 11,750	$ 24,109	$ 379,775
2	All service areas: no timing	Base: $35.90	Medium	$ 658	$ 14,015	$ 28,755	$ 452,962
3	All service areas: no timing	Base: $51.52	Medium	$ 764	$ 16,279	$ 33,401	$ 526,149
4	All service areas: no timing	Base: $20.29	Low	$ 1,104	$ 14,169	$ 28,338	$ 601,475
5	All service areas: no timing	Base: $35.90	Low	$ 1,317	$ 16,899	$ 33,799	$ 717,386
6	All service areas: no timing	Base: $51.52	Low	$ 1,530	$ 19,630	$ 39,260	$ 833,296
7	All service areas: no timing	High: $40.66	Medium	$ 690	$ 14,704	$ 30,169	$ 475,234
8	All service areas: no timing	High: $74.30	Medium	$ 919	$ 19,582	$ 40,177	$ 632,897
9	All service areas: no timing	High: $107.93	Medium	$ 1,148	$ 24,460	$ 50,186	$ 790,560
10	All service areas: no timing	High: $40.66	Low	$ 1,382	$ 17,730	$ 35,461	$ 752,660
11	All service areas: no timing	High: $74.30	Low	$ 1,840	$ 23,582	$ 47,225	$ 1,002,361
12	All service areas: no timing	High: $107.93	Low	$ 2,299	$ 29,457	$ 58,990	$ 1,252,063
13	Upgrades timed	Base	Medium	$ 520	$ 11,669	$ 23,179	$ 526,149
14	Upgrades timed	Base	Low	$ 1,042	$ 14,067	$ 27,245	$ 833,296
15	Upgrades timed	High	Medium	$ 714	$ 15,799	$ 31,882	$ 790,560
16	Upgrades timed	High	Low	$ 1,429	$ 19,030	$ 37,475	$ 1,252,063

Key Takeaway: Targeting lower efficiency customers can bring a 40+% upside.

The results shown in the previous two tables are in addition to the energy arbitrage benefits demonstrated in phase II of this project. The phase II energy benefits are shown in the following table.

Total System	Minimum	Maximum	Average
% Annual kWh Savings	0%	28%	28%
% Annual kW Savings	0%	47%	47%
% Avoided Cost	6%	35%	35%
% Customer Bill Reduction	10%	65%	47%
Scaled NPV (10yr, 7.09% discount) of Avoided Cost	$334MM	$3,712MM	$1,300MM
Scaled NPV (10yr, 7.09% discount) of Bill Reduction	$242MM	$2,442MM	$1,001MM

Key Takeaway: An additional $1 B in energy benefits are expected from distribution level DER control and dynamic load shifting.

Lessons Learned

The following lessons were learned from this project.

1) **Comprehensive integration of distributed energy resources (DER) with existing systems enables much greater benefits than can be achieved as "standalone" programs only.** Greater benefits are achieved through identification and targeting of customer preferences, deferral of specific distribution and transmission capital costs, better modeling of the covariance of weather, loads and prices on program risk and opportunity, and optimization of DER interactive systems at the planning and operational stages.
2) **Distributed energy resources can integrate at several levels with the existing infrastructure.** Distributed intelligence can effectively provide energy and ancillary services (regulation, spinning and non-spinning), transmission deferral and congestion mitigation, integration and stabilization of renewable and distributed generation technologies, T&D system optimization and capital project deferrals and consumer targeting of energy services.
3) **Distributed sensing and metering are necessary to capture greater DER benefits as existing AMI and meter-data-management systems (MDM) are insufficient to rapidly interact with T&D operations or with the dispatch of service crews in responding to outages.** Distributed sensing and metering can reduce inefficiencies by rapidly identifying excess or deficient capacity, faults, imbalances, degradation, aging and changes over time.
4) **The lack of direct interaction between smart meters and control of distributed energy resources or energy managing devices further limit DER effectiveness.** A lack of "behind the meter" services and siloed systems for information technology (IT) and operational technology (OT) has slowed the integration of smart meter data and smart grid devices.
5) **New DER and smart grid capabilities increasingly require multiple data sources that have not previously been combined, such as supply data, distribution data, customer data, customer preferences and wholesale grid data.** The harnessing of dynamic resources and capabilities, enabled by enhanced IT and OT, can enable and leverage much greater competitive advantage for the utility. When load-flows can be combined with DER and customer data additional major benefits can be captured.
6) **The harnessing of dynamic resources and capabilities, enabled by enhanced IT and OT, can enable and leverage much greater competitive advantage for the utility.** Specific processes can enable dynamic efficiencies, especially with expected new utility business models that "innovate at the speed of the market", such as through cospecialized assets that integrate and combine optimal services.
7) **A comprehensive method is needed to capture distributed benefits including value-of-service (VOS) differences among customers.** The best practices include targeting of specific customers, targeting of specific DER applications on the distribution and transmission systems, and bounding the uncertainty of key variables such as weather, loads, and prices through distributed optimization.

Key Takeaway: This project provides a business case analysis of the financial benefits for the utility and its customers by optimizing specific distributed energy and supply resources that are likely to occur in a future-state electric grid.

CURRENT STATE

- Smart meters/ AMI limited to comparative reporting
- Utility control of reliability based demand response programs
- Demand response = customer experiences discomfort or inconvenience in exchange for incentive payment
- TOU/CPP creates financial penalty for using electricity during on-peak
- Inclining block rates discourage additional volumetric usage of kWh
- As kWh volumes drop, prices rise – triggering more kWh reductions

Utility pricing and customer service are similar to historical Bell telephone companies

FUTURE STATE

- Dynamic choreograph of demand, distribution and supply by multiple parties using AMI data
- Optimization targets T&D system deficiencies and customer's preferred level of comfort and convenience to achieve bill savings and/or utility avoided cost savings
- Emphasis on providing value-added services, not just kWh commodity
- Grid resources managed to meet customer demand – whenever and however they want to use it

Utility pricing and customer service more akin to modern telecommunications companies