REDACTED

INFORMATION SHEET

PRESIDING: Chair Mitchell, Presiding; Commissioners Brown-Bland, Gray, Clodfelter, Duffley, Hughes, McKissick
PLACE: Held Via Videoconference
DATE: Thursday, September 10, 2020
TIME: 9:00 a.m. – 12:30 p.m.
DOCKET NOS.: E-7, Sub 1214; E-7, Sub 1213; E-7, Sub 1187
COMPANY: Duke Energy Carolinas, LLC; Duke Energy Progress, LLC
DESCRIPTION: E-7, Sub 1213, In the Matter of Petition of Duke Energy Carolinas, LLC, for Approval of Prepaid Advantage Program; E-7, Sub 1214, In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina; E-7, Sub 1187, In the Matter of Application of Duke Energy Carolinas, LLC, for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricane Florence and Michael and Winter Storm Diego

VOLUME NUMBER: 18

APPEARANCES
(See attached.)

WITNESSES
(See attached.)

EXHIBITS
(See attached.)

COPIES ORDERED: Downey, Culpepper, Holt, Cummings, Edmondson, Grantmyre, Dodge, Jost, Little, Luhr, Force, Townsend, Robinson, Kells, Mehta, Lee, Cress, Ross, Ledford, Smith, Schauer, Heslin, Su, Crystal and Beverly
CONFIDENTIAL TRANSCRIPTS and EXHIBITS ORDERED: Robinson, Heslin, Somers, Kells, Jagannathan, Mehta, Lee, Cress, Ross, Jenkins, Beverly, Ledford, Smith, Crystal, Su, Force, Townsend, Downey, Culpepper, Cummings, Dodge, Edmondson, Grantmyre, Holt, Jost, Little, and Luhr

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DATE: Thursday, September 10, 2020

TIME: 9:00 A.M. - 12:30 P.M.

DOCKET NO.: E-7, Sub 1214

E-7, Sub 1213

E-7, Sub 1187

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

DOCKET NO. E-7, SUB 1214

Application of Duke Energy Carolinas, LLC,

for Adjustment of Rates and Charges Applicable to

Electric Utility Service in North Carolina

DOCKET NO. E-7, SUB 1213

Petition of Duke Energy Carolinas, LLC,

for Approval of Prepaid Advantage Program

DOCKET NO. E-7, SUB 1187

Application of Duke Energy Carolinas, LLC,

for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego

VOLUME 18

A P P E A R A N C E S:

FOR DUKE ENERGY CAROLINAS, LLC:

Camal Robinson, Esq., Associate General Counsel
Brian Heslin, Esq., Deputy General Counsel
Duke Energy Corporation
550 South Tryon Street
Charlotte, North Carolina 28202

Lawrence B. Somers, Esq., Deputy General Counsel
Duke Energy Corporation
410 South Wilmington Street
Raleigh, North Carolina 27601

James H. Jeffries, IV, Esq.
McGuireWoods LLP
201 North Tryon Street, Suite 3000
Charlotte, North Carolina 28202

Andrea Kells, Esq.
McGuireWoods LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd:

Molly McIntosh Jagannathan, Esq., Partner
Kiran H. Mehta, Esq., Partner
Troutman Pepper Hamilton Sanders LLP
301 South College Street, Suite 3400
Charlotte, North Carolina 28202

Brandon F. Marzo, Esq.
Troutman Pepper
600 Peachtree Street, NE, Suite 3000
Atlanta, Georgia 30308

FOR SIERRA CLUB:
Bridget Lee, Esq.
Sierra Club
9 Pine Street
New York, New York 10005

Catherine Cralle Jones, Esq.
Law Office of F. Bryan Brice, Jr.
127 W. Hargett Street
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd:

FOR NC JUSTICE CENTER, NC HOUSING COALITION, NATURAL RESOURCES DEFENSE COUNCIL and SIERRA CLUB:

Gudrun Thompson, Esq., Senior Attorney
David L. Neal, Esq., Senior Attorney
Tirrill Moore, Esq., Associate Attorney
Southern Environmental Law Center
601 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

FOR CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES III:

Christina D. Cress, Esq.
Bailey & Dixon, LLP
Post Office Box 1351
Raleigh, North Carolina 27602

FOR CAROLINA UTILITY CUSTOMERS ASSOCIATION, INC.:

Robert F. Page, Esq.
Crisp & Page, PLLC
4010 Barrett Drive, Suite 205
Raleigh, North Carolina 27609

A P P E A R A N C E S Cont'd:

FOR NC WARN:
Matthew D. Quinn, Esq.
Lewis & Roberts PLLC
3700 Glenwood Avenue, Suite 410
Raleigh, North Carolina 27612

FOR VOTE SOLAR:
Thadeus B. Culley, Esq., Regulatory Counsel
Senior Regional Director
1911 Ephesus Church Road
Chapel Hill, North Carolina 27517

FOR NORTH CAROLINA LEAGUE OF MUNICIPALITIES:
Deborah Ross, Esq.
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

FOR NORTH CAROLINA CLEAN ENERGY BUSINESS ALLIANCE:
Karen Kemerait, Esq.
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd:

FOR THE COMMERCIAL GROUP:
Alan R. Jenkins, Esq.
Jenkins At Law, LLC
2950 Yellowtail Avenue
Marathon, Florida 33050

Brian O. Beverly, Esq.
Young Moore and Henderson, P.A.
3101 Glenwood Avenue
Raleigh, North Carolina 27622

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:
Peter H. Ledford, Esq., General Counsel
Benjamin Smith, Esq., Regulatory Counsel
North Carolina Sustainable Energy Association
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

A P P E A R A N C E S Cont'd:

FOR THE TECH CUSTOMERS:
Marcus W. Trathen, Esq.
Craig D. Schauer, Esq.
Matthew B. Tynan, Esq.
Charles E. Coble, Esq.
Brooks, Pierce, McLendon, Humphrey & Leonard, L.L.P.
150 Fayetteville Street, Suite 1700
Raleigh, North Carolina 27601

FOR BIOLOGICAL DIVERSITY AND APPALACHIAN VOICES:
Howard M. Crystal, Esq.
Senior Attorney
Jean Su, Esq.
Staff Attorney and Energy Director
Biological Diversity
1411 K Street NW, Suite 1300
Washington, DC 20005

A P P E A R A N C E S Cont'd:

FOR HARRIS TEETER:

Kurt J. Boehm, Esq.
Jody Kyler Cohn, Esq.
Boehm, Kurtz, & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202

Benjamin M. Royster, Esq.
Royster and Royster, PLLC
851 Marshall Street
Mount Airy, North Carolina 27030

FOR THE USING AND CONSUMING PUBLIC AND ON BEHALF OF THE STATE AND ITS CITIZENS IN THIS MATTER THAT AFFECTS THE PUBLIC INTEREST:

Margaret A. Force, Esq., Assistant Attorney General
Teresa Townsend, Esq., Special Deputy Attorney General
North Carolina Department of Justice
Post Office Box 629
Raleigh, North Carolina 27603

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EXAMINATIONS

E X H I B I T S

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1214

In the Matter of:	)
Application of Duke Energy Carolinas,	)
LLC for Adjustment of Rates and	)
Charges Applicable to Electric Service	)
in North Carolina	)

DIRECT TESTIMONY OF
JUSTIN R. BARNES
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT JRB-1

JUSTIN R. BARNES

(919) 825-3342, jbarnes@eq-research.com

EDUCATION

Michigan Technological University Houghton, Michigan
Master of Science, Environmental Policy, August 2006
Graduate-level work in Energy Policy.

University of Oklahoma Norman, Oklahoma
Bachelor of Science, Geography, December 2003
Area of concentration in Physical Geography.

RELEVANT EXPERIENCE

Director of Research, July 2015 – present
Senior Analyst & Research Manager, March 2013 – July 2015
EQ Research, LLC and Keyes, Fox & Wiedman, LLP Cary, North Carolina

- Oversee state legislative, regulatory policy, and general rate case tracking service that covers policies such as net metering, interconnection standards, rate design, renewables portfolio standards, state energy planning, state and utility incentives, tax incentives, and permitting. Responsible for service design, formulating improvements based on client needs, and ultimate delivery of reports to clients. Expanded service to cover energy storage.
- Oversee and perform policy research and analysis to fulfill client requests, and for internal and published reports, focused primarily on drivers of distributed energy resource (DER) markets and policies.
- Provide expert witness testimony on topics including cost of service, rate design, distributed energy resource (DER) value, and DER policy including incentive program design, rate design issues, and competitive impacts of utility ownership of DERs.
- Managed the development of a solar power purchase agreement (PPA) toolkit for local governments, a comprehensive legal and policy resource for local governments interested in purchasing solar energy, and the planning and delivery of associated outreach efforts.

Senior Policy Analyst, January 2012 – May 2013;
Policy Analyst, September 2007 – December 2011
North Carolina Solar Center, N.C. State University Raleigh, North Carolina

- Responsible for researching and maintaining information for the Database of State Incentives for Renewables and Efficiency (DSIRE), the most comprehensive public source of renewables and energy efficiency incentives and policy data in the United States.
- Managed state-level regulatory tracking for private wind and solar companies.
- Coordinated the organization's participation in the SunShot Solar Outreach Partnership, a U.S. Department of Energy project to provide outreach and technical assistance for local governments to develop and transform local solar markets.
- Developed and presented educational workshops, reports, administered grant contracts and associated deliverables, provided support for the SunShot Initiative, and worked with diverse group of project partners on this effort.
- Responsible for maintaining the renewable portfolio standard dataset for the National Renewable Energy Laboratory for use in its electricity modeling and forecasting analysis.
- Authored the *DSIRE RPS Data Updates*, a monthly newsletter providing up-to-date data and historic compliance information on state RPS policies.

- Responded to information requests and provided technical assistance to the general public, government officials, media, and the energy industry on a wide range of subjects, including federal tax incentives, state property taxes, net metering, state renewable portfolios standard policies, and renewable energy credits.
- Extensive experience researching, understanding, and disseminating information on complex issues associated with utility regulation, policy best practices, and emerging issues.

SELECTED ARTICLES and PUBLICATIONS

- EQ Research and Synapse Energy Economics for Delaware Riverkeeper Network. *Envisioning Pennsylvania's Energy Future*. 2016.
- Barnes, J., R. Haynes. *The Great Guessing Game: How Much Net Metering Capacity is Left?*. September 2015. Published by EQ Research, LLC.
- Barnes, J., Kapla, K. *Solar Power Purchase Agreements (PPAs): A Toolkit for Local Governments*. July 2015. For the Interstate Renewable Energy Council, Inc. under the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *2013 RPS Legislation: Gauging the Impacts*. December 2013. Article in Solar Today.
- Barnes, J., C. Laurent, J. Uppal, C. Barnes, A. Heinemann. *Property Taxes and Solar PV: Policy, Practices, and Issues*. July 2013. For the U.S. DOE SunShot Solar Outreach Partnership.
- Kooles, K, J. Barnes. *Austin, Texas: What is the Value of Solar; Solar in Small Communities: Gaston County, North Carolina*; and *Solar in Small Communities: Columbia, Missouri*. 2013. Case Studies for the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *The Report of My Death Was An Exaggeration: Renewables Portfolio Standards Live On*. 2013. For Keyes, Fox & Wiedman.
- Barnes, J. *Why Tradable SRECs are Ruining Distributed Solar*. 2012. Guest Post in Greentech Media Solar.
- Barnes, J., multiple co-authors. *State Solar Incentives and Policy Trends*. Annually for five years, 2008-2012. For the Interstate Renewable Energy Council, Inc.
- Barnes, J. *Solar for Everyone?* 2012. Article in Solar Power World On-line.
- Barnes, J., L. Varnado. *Why Bother? Capturing the Value of Net Metering in Competitive Choice Markets*. 2011. American Solar Energy Society Conference Proceedings.
- Barnes, J. *SREC Markets: The Murky Side of Solar*. 2011. Article in State and Local Energy Report.
- Barnes, J., L. Varnado. *The Intersection of Net Metering and Retail Choice: an overview of policy, practice, and issues*. 2010. For the Interstate Renewable Energy Council, Inc.

TESTIMONY & OTHER REGULATORY ASSISTANCE

Virginia State Corporation Commission. Docket No. PUR-2019-00060. November 2019. On behalf of Appalachian Voices. Old Dominion Power Company general rate case application. Analysis of the cost basis for the residential customer charge, proposal to change the residential customer charge from a monthly charge to a daily charge, and design of proposed customer green power program and utility owned commercial behind the meter solar proposal. Proposed modified optional rate structure for mid- to large-size non-residential customers with on-site solar and/or low load factors.

Georgia Public Service Commission. Docket No. 42516. October 2019. On behalf of Georgia Interfaith Power and Light, Southface Energy Institute, and Vote Solar. Georgia Power Company general rate case application. Analysis of the cost basis for the residential customer charge, the validity of the utility's minimum-intercept study, and a proposal to change the residential customer charge from a monthly charge to a daily charge.

Hawaii Public Utilities Commission. Docket No. 2018-0368. July 2019. On behalf of the Hawaii PV Coalition. Hawaii Electric Light Company (HELCO) general rate case application. Provided analysis of

HELCO's proposed changes to its decoupling rider to make the decoupling charge non-bypassable and the alignment of the proposed modifications with state policy goals and the policy rationale for decoupling.

Virginia State Corporation Commission. Docket No. PUR-2019-00067. July 2019.* On behalf of the Southern Environmental Law Center. Appalachian Power Company residential electric vehicle (EV) rate proposal. Provided review and analysis of the proposal and developed comments discussing principles of time-of-use (TOU) rate design and proposing modifications to the Company's proposal to support greater equity among rural ratepayers and greater rate enrollment. ***This work involved comment preparation rather than testimony.**

New York Public Service Commission. Case No. 19-E-0065. May 2019. On behalf of The Alliance for Solar Choice. Consolidated Edison (ConEd) general rate case application. Provided review and analysis of the competitive impacts and alignment with state policy of ConEd's energy storage, distributed energy resource management system, and earnings adjustment mechanism (EAM) proposals. Proposed model for improving the utilization of customer-sited storage in existing demand response programs and an alternative EAM supportive of utilization of third party-owned battery storage.

South Carolina Public Service Commission. Docket No. 2018-318-E. March 2019. On behalf of Vote Solar. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, AMI-enabled rate design plans, excess deferred income tax rider rate design, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

South Carolina Public Service Commission. Docket No. 2018-319-E. February 2019. On behalf of Vote Solar. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, AMI-enabled rate design plans, excess deferred income tax rider rate design, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

New Orleans City Council. Docket No. UD-18-07. February 2019. On behalf of the Alliance for Affordable Energy. Entergy New Orleans general rate case application. Analysis of the cost basis for the residential customer charge, rate design for AMI, DSM and Grid Modernization Riders, and DSM program performance incentive proposal. Developed recommendations for the residential customer charge, rider rate design, and a revised DSM performance incentive mechanism.

New Hampshire Public Utilities Commission. Docket No. DE 17-189. May 2018. On behalf of Sunrun Inc. Review of Liberty Utilities application for approval of customer-sited battery storage program, analysis of time-of-use rate design, program cost-benefit analysis, cost-effectiveness of utility-owned vs. non-utility owned storage assets. Developed a proposal for an alternative program utilizing non-utility owned assets under an aggregator model with elements for benefits sharing and ratepayer risk reduction.

North Carolina Utilities Commission. Docket No. E-7 Sub 1146. January 2018. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

Ohio Public Utilities Commission. Docket No. 17-1263-EL-SSO. November 2017*. On behalf of the Ohio Environmental Council. ***Testimony prepared but not filed due to settlement in related case.** Duke Energy Ohio proposal to reduce compensation to net metering customers. Provided analysis of capacity value of solar net metering resources in the PJM market and distribution of that value to customers. Also analyzed the cost basis of the utility proposal for recovery of net metering credit costs, focused on PJM settlement protocols and how the value of DG customer exports is distributed among ratepayers, load-serving entities, and distribution utilities based on load settlement practices.

North Carolina Utilities Commission, Docket No. E-2 Sub 1142. October 2017. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and advanced metering infrastructure deployment plans and cost-benefit analysis.

Public Utility Commission of Texas, Control No. 46831. June 2017. On behalf of the Energy Freedom Coalition of America. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate DG rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits, and alignment of demand ratchets with cost causation principles and state policy goals, focused on impacts on customer-sited storage.

Utah Public Service Commission, Docket No. 14-035-114. June 2017. On behalf of Utah Clean Energy. Rocky Mountain Power application for separate distributed generation (DG) rate class. Provided analysis of grandfathering of existing DG customers and best practices for review of DG customer rates and DG value. Developed proposal for addressing revisions to DG customer rates in the future.

Colorado Public Utilities Commission, Proceeding No. 16A-0055E. May 2016. On behalf of the Energy Freedom Coalition of America. Public Service Company of Colorado application for solar energy purchase program. Analysis of program design from the perspective of customer demand and needs, and potential competitive impacts. Proposed alternative program design.

Public Utility Commission of Texas, Control No. 44941. December 2015. On behalf of Sunrun, Inc. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits.

Oklahoma Corporation Commission, Cause No. PUD 201500271. November 2015. On behalf of the Alliance for Solar Choice. Analysis of Oklahoma Gas & Electric proposal to place distributed generation customers on separate rates, rate impacts, cost basis of proposal, and alignment with rate design principles.

South Carolina Public Service Commission, Docket No. 2015-54-E. May 2015. On behalf of The Alliance for Solar Choice. South Carolina Electric & Gas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-53-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Carolinas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-55-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Progress application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2014-246-E. December 2014. On behalf of The Alliance for Solar Choice. Generic investigation of distributed energy policy. Distributed energy best practices, including net metering and rate design for distributed energy customers.

AWARDS, HONORS & AFFILIATIONS

- Solar Power World Magazine, Editorial Advisory Board Member (October 2011 – March 2013)
- Michigan Tech Finalist for the Midwest Association of Graduate Schools Distinguished Master's Thesis Awards (2007)
- Sustainable Futures Institute Graduate Scholar Michigan Tech University (2005-2006)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1214

In the Matter of:	)
Application of Duke Energy Carolinas,	)
LLC for Adjustment of Rates and	)
Charges Applicable to Electric Service	)
in North Carolina	)

DIRECT TESTIMONY OF
JUSTIN R. BARNES
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT JRB-2

Exhibit JRB-2

I/A

Driving Transportation Electrification Forward in New York

Considerations for Effective Transportation Electrification Rate Design

Prepared for Natural Resources Defense Council

June 25, 2018

AUTHORS

Melissa Whited
Avi Allison
Rachel Wilson

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

Acknowledgements

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EXECUTIVE SUMMARY

Electrifying the transportation sector will be necessary to achieve large-scale greenhouse gas reductions. Converting internal combustion engine (ICE) vehicles to electric vehicles (EVs) could also provide substantial net benefits to society through substantially reducing transportation fuel costs while simultaneously reducing electricity rates through better utilization of existing infrastructure. These benefits are far from certain, however. Achieving these benefits hinges on two key factors:

1) Charging EVs in a manner that minimizes costs to the grid, and

2) Widespread adoption of EVs.

Electric utilities are in a unique position to influence both of these factors through electric rate design.

Managing peak demand is a key challenge for electric utilities. As the penetration of EVs increases, charging EVs during times of peak demand could exacerbate grid constraints, require the construction of new power plants or transmission and distribution infrastructure, and increase costs for customers.[1] In addition, certain electric rate structures can pose financial barriers to potential EV customers and owners of public EV charging stations. These barriers could reduce demand for EVs and slow the transition to the cleaner transportation system necessary to meet state goals.

To avoid these pitfalls, electric utilities should provide EV customers with clear electricity price signals to encourage charging off-peak. Further, well-designed electricity pricing can help encourage the adoption of EVs and support the financial viability of public EV charging stations. This report examines best practices in EV rate design and provides comments on New York utilities' EV rate design proposals submitted in Docket 18-E-0206.

Rate Design Options

Standard, time-invariant electricity rates do little to encourage EV adoption or optimal charging times. In fact, these rates may even directly discourage efficient charging practices, since customers are apt to charge when it is most convenient to them, rather than when it is most beneficial to the grid. In contrast, time-varying rates convey price signals that better reflect the cost of producing and delivering energy during different hours. Time-varying rates include time-of-use (TOU) rates, critical peak pricing, peak time rebates, and dynamic hourly pricing. In addition, some utility rates include a demand charge, which is typically based on a customer's maximum consumption during a month.

Each of the above rates has advantages and drawbacks. However, TOU rates are the most popular form of time-varying rate, both for EV customers and non-EV customers. TOU rates are popular for several reasons:

[1] Current penetrations of EVs are unlikely to have a material impact on the grid, but as adoption increases, more attention to load management is warranted.

- **Effectiveness:** TOU rates have proven to be highly effective in shifting EV load. Both whole-house and EV-only TOU rates have been implemented at all three of California's large investor-owned utilities (IOU) and have been extremely successful in motivating customers to avoid charging on-peak. At Pacific Gas & Electric, 93 percent of charging on the EV-only rate occurs during off-peak hours, while at Southern California Edison, 88 percent of charging is off-peak.[2]

- **Simplicity:** TOU rates provide an easy-to-understand price signal that reflects general trends in utility costs, without requiring customers to monitor hourly energy prices. TOU rates are particularly well suited to "set it and forget it" technologies, such as the timers on many EV chargers.

- **Efficiency:** TOU rates can be designed by layering different types of utility costs (generation, transmission, and distribution) to reflect the temporal variability of all three.

Section 3.2 below provides more detail regarding the methods that can be used for designing TOU rates in a manner consistent with the time-varying nature of generation, transmission, and distribution costs.

Demand charges, which are typically based on a customer's maximum usage during a month, are generally not well suited to providing price signals that will support EV adoption. In fact, demand charges can work to discourage critical EV charging infrastructure deployment while the EV market is still in early development. A demand charge that applies during any hour of the day effectively becomes a fixed charge that cannot be avoided by scheduling EV charging for off-peak periods. For public charging stations, demand charges can undermine the financial viability of the station. While the maximum electricity demand at these stations is very high, energy use tends to be low due to the limited number of EVs on the road today. This means that demand charges tend to dominate the electricity bills for these stations, and these costs are very difficult to recover from the low number of EV customers.

To address this problem, some utilities have temporarily reduced or eliminated demand charges for public charging infrastructure, opting instead to price electricity using TOU rates. Cross-subsidization due to such rates is unlikely as long as electricity is priced at or above the utility's marginal cost of service,[3] since EV stations are supporting incremental load growth, rather than representing existing load on the system.[4]

[2] Synapse Analysis of Joint Utilities Load Research Report, December 2017.

[3] Any required distribution upgrades directly related to the charging station should also be recovered from the charging station owner in order to avoid shifting these costs on to other customers.

[4] Existing tariffs are designed to recover embedded costs from existing load, which enables incremental load to be priced at marginal cost, at least during the early years of EV adoption.

Metering Technologies for EV-Only Rates

Customers may prefer an EV-only TOU rate to a whole-house rate because it is much easier for customers to monitor and control the timing of EV charging than the use of other appliances in the home. However, EV-only rates require a separate revenue-grade meter or the use of submetering technology to record electricity use that is specifically attributable to EV charging.

Although a second meter makes it easy to apply TOU rates only to EV charging, the additional meter and installation charges involved can be formidable. The installation can cost thousands of dollars up front for customers, eliminating virtually all of the fuel cost savings associated with the EV-only rate. Some utilities also assess a second customer charge for the second meter. These high costs have contributed to very low customer enrollment in EV-only TOU rates that require a second meter.

Several different submetering technologies are available. These include:

- Stand-alone submeters such as the WattBox™ from eMotorWerks, with a cost of approximately $250. In some pilot programs, connectivity and data transfer issues have been a problem. In addition, installation typically requires an electrician and will incur an additional cost.

- Submeters integrated with the EV supply equipment (EVSE). At-home EVSE are generally Level 2 charging with costs typically between $500 to $900. The installation of these EVSE requires an electrician at additional cost. EVSE-integrated submeters have been used by some municipal utilities, is being piloted at a large scale in California, and will soon be piloted in Minnesota.

- Mobile (in-car) submeters such as the FleetCarma C2 device. This device is “plug-and-play,” allowing the EV owner to simply plug it into a port under the dash of the vehicle. The device then collects vehicle charging and driving data and sends the data securely to FleetCarma servers over the cellular network. However, the annual costs to the utility associated with the use of this device at present appear quite high.
- On-board metering (integrated into the vehicle itself) may be an option for off-peak charging rebate programs and could potentially be extended to other rate structures in the future. A key barrier to extending on-board metering to other rate structures is the requirement for revenue grade metering and the implications for billing responsibility.

Each metering option has certain advantages and drawbacks. While a second utility meter is a straightforward option, the costs of installation can be prohibitively high, and customer charges associated with a second meter can deter customers. Submetering is promising, particularly if installation costs can be reduced further and data transfer issues can be fully resolved.

Maximizing Customer Enrollment

To achieve the benefits promised by time-varying rates, customer enrollment levels must be maximized. Simply designing a rate well is not sufficient to ensuring its success. Due to customer inertia, low levels of customer enrollment are common when customers are required to actively opt-in to the rate. Currently enrollment levels in most New York utilities' existing TOU rates are below 0.5 percent.

Electric utilities can achieve high levels of customer enrollment through defaulting customers onto a rate (through an opt-out design). Where defaulting customers onto a time-varying rate is not feasible, utilities must actively encourage enrollment through a combination of education, outreach, and incentives. In addition, it is important to ensure that utility incentives, auto dealership incentives, and customer incentives are all aligned. Activities to maximize EV customer enrollment in EV rates may include:

- **Website Tools:** Rate comparison calculators, such as Southern California Edison's Electric Vehicle Rate Assistant Tool, provide an easy way for customers to compare their potential cost savings over several different rate options.

- **Dealership Education and Incentives:** Auto sales representatives often have little to no understanding of the rates available to EV drivers, or the potential savings these could provide to customers. In California, a collaboration of organizations developed and conducts a dealership training curriculum, and a $250 dealership incentive is provided for each EV purchase in which the customer also signs up for an EV rate.[5]

- **Direct Outreach to EV Customers:** It can be difficult for a utility to identify which of its customers have purchased an EV. To identify customers, utilities may be able to work with state agencies to access Department of Motor Vehicle registration records and directly contact EV drivers. Some utilities also offer gift cards or other rewards to customers. For example, Salt River Project in Arizona provides EV customers with a $50 gift card simply for signing up for the utility's EV mailing list. Establishing these points of contact can be an important first step to educating and enrolling customers in an EV rate.

- **Price Guarantees:** Price guarantees may be offered for the first six months or year after a customer signs up for a new rate. These guarantees ensure that the customer will not pay more on the time-varying rate than they would on a standard rate, thereby reducing the customer's risk of signing up for a rate structure that is new to them.

Assessment of New York Utility EV Rate Proposals

The New York electric IOUs recently submitted proposals for residential EV tariffs to comply with New York Public Service Law Section 66-o(2). The overall structure of these proposed rates is sound, but there are several key areas where the proposals could be strengthened. In particular, many of the

[5] The monetary incentive was recently approved for SDG&E. *See:* California Public Utilities Commission. Decision on the Transportation Electrification Priority Review Projects. Decision 18-01-024. January 11, 2018, page 39.

proposals fail to deliver the fuel cost savings needed to encourage customers to enroll in the rate and to motivate EV purchase decisions.

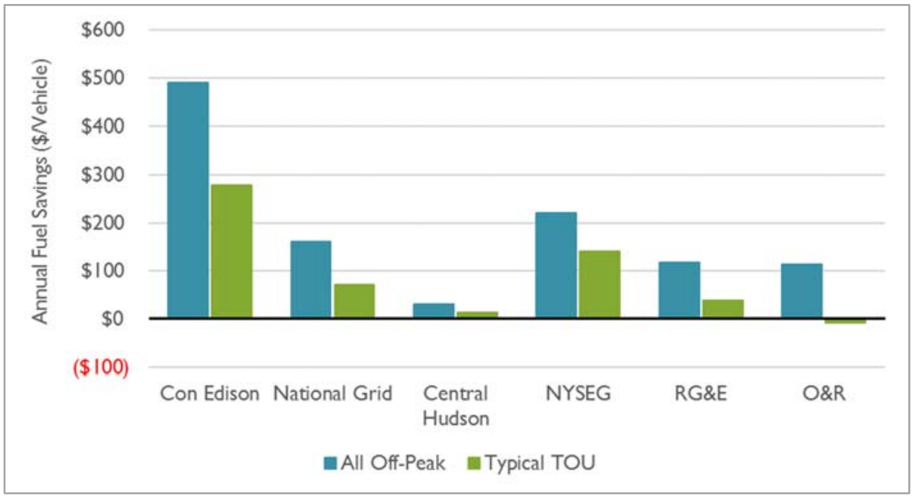
- **Metering:** None of the New York IOUs have proposed a submetering option using an EVSE for their EV rates, nor have they explained why submetering was not proposed. Instead, the IOUs that offer an EV-only rate would require a second traditional utility meter, with the exception of Consolidated Edison Company of New York's (Con Edison) ongoing SmartCharge NY program. The high cost of installing a second meter could dampen enrollment levels in EV-only TOU rates.

- **Rate Structure and Price Guarantee:** Each of the proposed residential EV tariffs use a TOU rate structure and include a one-year price guarantee that ensures that customers will not pay more on a whole-house TOU rate than they would have if they had remained on their original rate. These are very positive design decisions that will help to attract customers to the rate.

- **Fuel Cost Savings under Whole-House TOU Rate:** To achieve New York's policy goals, the ability for EV drivers to achieve fuel savings on the rate should be a central component of the rate design. Fuel cost savings are important for encouraging customers to adopt the rate and to motivate EV adoption. Synapse evaluated two metrics for assessing a customer's fuel cost savings: (1) savings on the TOU rate relative to the standard rate, and (2) savings from fueling the EV on the TOU rate relative to the cost of fueling an ICE vehicle. In both cases, we assumed a battery electric vehicle (BEV) with a range of 100 miles, similar to a Nissan Leaf or a BMW i3.

  Our analysis indicates that the fuel cost savings of the proposed TOU rates relative to standard rates vary substantially across utilities, as shown in the figure below. The figure shows fuel cost savings under two different scenarios: one in which 100 percent of the customer's EV charging occurs off-peak; and the other assuming more typical customer behavior in which most, but not all, charging occurs off-peak.

Figure ES-1. Whole-house TOU rate annual fuel cost savings relative to standard rate

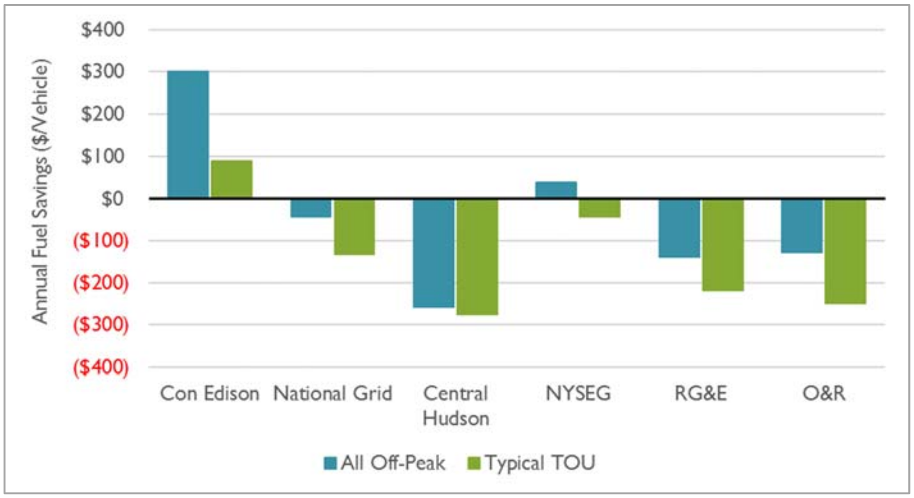


Source: Synapse Energy Economics analysis.

The whole-house rates proposed by Con Edison and New York State Electric and Gas (NYSEG) offer the greatest potential savings, with Con Edison customers experiencing annual fuel cost savings of approximately $500. In contrast, Central Hudson's rate (which has a low price differential between on-peak and off-peak), average annual savings amount to less than $50 even if all charging takes place during off-peak hours.

- **Fuel Cost Savings under EV-Only TOU Rate:** Con Edison, Orange and Rockland Utilities (O&R), NYSEG, and Rochester Gas and Electric (RG&E) include the option for customers to charge EVs under a separately metered TOU rate, rather than under the whole-house TOU rate. However, separately metered customers would likely have to pay an extra customer charge. The figure below shows that customers receive lower fuel cost savings from switching to the utilities' EV-only TOU rate, as the additional customer charge offsets the savings associated with a lower off-peak energy charge. In fact, we estimate that typical separately metered EV customers would incur *increased* fuel costs at every utility other than Con Edison. Customers of O&R could incur additional EV fuel costs of $250 by switching to the separate-meter TOU rate.

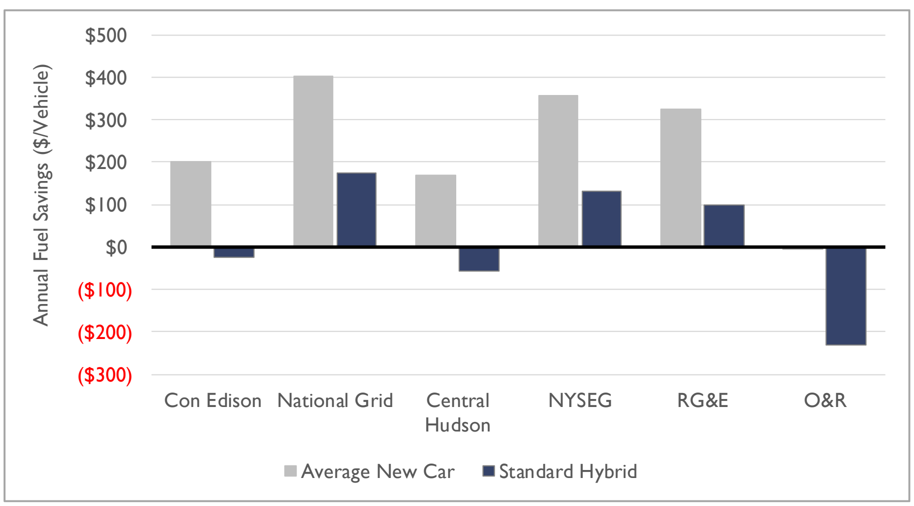
Figure ES-2. EV-only TOU rate annual fuel cost savings relative to standard rate



Source: Synapse Energy Economics analysis.

- **Fuel Cost Savings Relative to Gasoline-Powered Vehicles:** The fuel cost savings provided by EVs on the proposed TOU rates relative to ICEs also vary greatly depending on the utility and the ICE in question. The figure below presents our calculated fuel cost savings for each utility for a typical 100-mile BEV on a whole-house TOU rate relative to two alternative types of ICEs: a typical new car with an efficiency of 38 mpg, and a standard hybrid with an efficiency of 55 mpg.

Figure ES-3. Annual fuel cost savings on whole-house TOU rate relative to alternative ICE types



Source: Synapse Energy Economics analysis.

In nearly all utility service territories, the whole-house TOU rate would generate positive fuel cost savings relative to a typical new gasoline-powered vehicle. However, when compared to a standard hybrid vehicle, such as a Toyota Prius, EV fuel savings largely disappear. This comparison is important, because customers considering purchasing an

EV are likely to compare these vehicles to high-efficiency ICE options, such as standard hybrids. At three of the six IOUs, an EV customer would likely have higher fuel costs relative to a hybrid vehicle—more than $200 higher in O&R's territory.

One of the primary reasons that O&R's EV-only rate option offers the lowest fuel cost savings relative to both a standard residential rate and an ICE is that it has a relatively high customer charge of $12.00 per month. This charge is nearly three times greater than any other utility. This additional customer charge could potentially be avoided if the utility employed submetering rather than a second meter. However, it is not clear that a second customer charge is even fully justified for a second meter, given that many customer-related costs (such as the cost of the final line transformer and service drop) would not change upon the installation of a second meter on the customer's premises.

- **Ratio Between Peak and Off-Peak Rates.** Higher ratios between on-peak and off-peak price help to encourage EV customers to charge during off-peak hours and better enable customers to achieve fuel cost savings. Con Edison and O&R's proposed on-peak to off-peak price ratios are greater than 14:1 in the summer months and greater than 5:1 in the winter months. In contrast, Central Hudson's rate has a ratio of only 1.2:1 throughout the year.

  The IOUs also offer standard offer supply service TOU rates for customers who do not purchase electricity supply from a retail supplier. Con Edison's TOU standard offer service rates vary dramatically between peak summer hours and other times of the year, whereas the TOU standard offer service of NYSEG and RG&E do not exhibit marked differences between peak and off-peak hours. The reason for this differential could lie in zonal wholesale market prices, but it is worth reviewing the price differentials to ensure that the standard offer service prices contribute to an efficient overall TOU price.

- **Customer Enrollment in TOU Rates.** To date, enrollment in the New York IOUs' TOU rates has been very low, with most enrollment levels below 0.5 percent of residential customers. Although not required by the law, it is clear that to encourage EV customers to enroll in the utilities' new TOU rates, the IOUs must do more than simply establish the rate. The utilities must actively encourage enrollment through a combination of education, outreach, and incentives for both customers and auto dealerships. In addition, utility incentives should also be aligned with enrolling customers in EV rates. This could take the form of Earnings Adjustment Mechanisms that establish targets not only for customer adoption of EVs, but also for enrollment in an EV rate.

In conclusion, the New York utilities have a unique opportunity to influence EV adoption and steer EV charging practices to benefit the grid and society. The utilities' recent proposals represent a step in the right direction but require additional work to unlock their full potential. Specifically, we offer six recommendations:

1) Utilities with low price differentials between on-peak and off-peak rates increase the price ratio to motivate off-peak charging and enable greater fuel savings;
2) Ensure that a customer who charges mostly off-peak achieves fuel savings relative to a customer who remains on a standard rate and charges only on-peak;
3) Reduce or eliminate the customer charge for second meters;
4) Explore submetering as a means to lower the cost for EV-only rates;
5) Evaluate whether the proposed rate will provide sufficient fuel savings to encourage customers to adopt EVs over high-efficiency ICE vehicles; and
6) Endeavor to maximize customer enrollment through education, outreach, and incentives.

Finally, we recommend that these actions on residential rate design be complemented by an analysis of commercial and industrial rates to determine whether modifications are warranted to support EV charging stations, fleet electrification, and workplace charging.

1. INTRODUCTION

New York State will need to electrify its transportation sector to achieve large-scale greenhouse gas reductions.[6] This electrification could also substantially reduce transportation fuel costs, while simultaneously putting downward pressure on electricity rates through better utilization of existing infrastructure. In short, converting internal combustion engine (ICE) vehicles to electric vehicles (EVs) could provide substantial net benefits to society.[7] However, the extent to which those potential benefits are achieved hinges upon appropriate utility rate design.

Utility rate design is a key motivator for influencing whether customers charge EVs in a manner compatible with grid conditions, as well as the extent to which customers save money when refueling. Rapid adoption of EVs will be needed to meet energy policy goals, and studies reveal that saving money relative to an ICE is one of the most important motivators of EV purchase decisions.[8] Thus, the viability of an essential pathway to mitigate climate change and reduce America's exposure to the volatility of the global oil market depends upon appropriate rate design and on the decisions made by state utility regulators.

In New York, transportation accounts for roughly 34 percent of greenhouse gas emissions, whereas the state's electric power sector comprises less than 20 percent of emissions.[9] Addressing transportation emissions will be critical for achieving Governor Andrew Cuomo's target of reducing economy-wide

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[6] *See:* Daniel Steinberg et al., "Electrification & Decarbonization: Exploring U.S. Energy Use and Greenhouse Gas Emissions in Scenarios with Widespread Electrification and Power Sector Decarbonization" (NREL, July 2017), https://www.nrel.gov/docs/fy17osti/68214.pdf; J.H. Williams et al., "Pathways to Deep Decarbonization in the United States" (The U.S. report of the Deep Decarbonization Pathways Project of the Sustainable Development Solutions Network and the Institute for Sustainable Development and International Relations, 2014); International Energy Agency, "Transport, Energy, and CO2: Moving Toward Sustainability" (Paris: IEA/OECD, 2009), https://www.iea.org/publications/freepublications/publication/transport2009.pdf; National Research Council, "Transitions to Alternative Vehicles and Fuels" (Washington, DC, 2013), https://www.nap.edu/catalog/18264/transitions-to-alternative-vehicles-and-fuels.

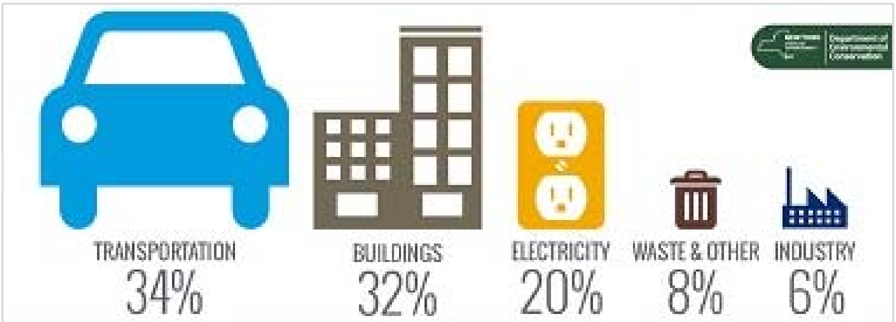
[7] We use the term "electric vehicles" to refer to both plug-in hybrid electric vehicles and battery electric vehicles.

[8] For example, a survey of nearly 20,000 EV owners in California found that fuel cost savings are the number one motivator for an EV purchase. In addition, NREL's annual surveys for the years 2015–2017 show that fuel cost savings consistently ranks as either the first or second most important reason for considering EVs. *See:* Center for Sustainable Energy (2016). California Air Resources Board Clean Vehicle Rebate Project, EV Consumer Survey Dataset: http://cleanvehiclerebate.org/eng/survey-dashboard/ev. *and* Mark Singer, "The Barriers to Acceptance of Plug-in Electric Vehicles: 2017 Update" (NREL, November 2017), https://www.nrel.gov/docs/fy18osti/70371.pdf.

[9] New York Department of Environmental Conservation, Mitigation of Climate Change: https://www.dec.ny.gov/energy/99223.html

greenhouse gas emissions by 40 percent by 2030 and 80 percent by 2050,[10] and for complying with Zero Emission Vehicle (ZEV) regulations that will require approximately 800,000 EVs in New York by 2025.[11]

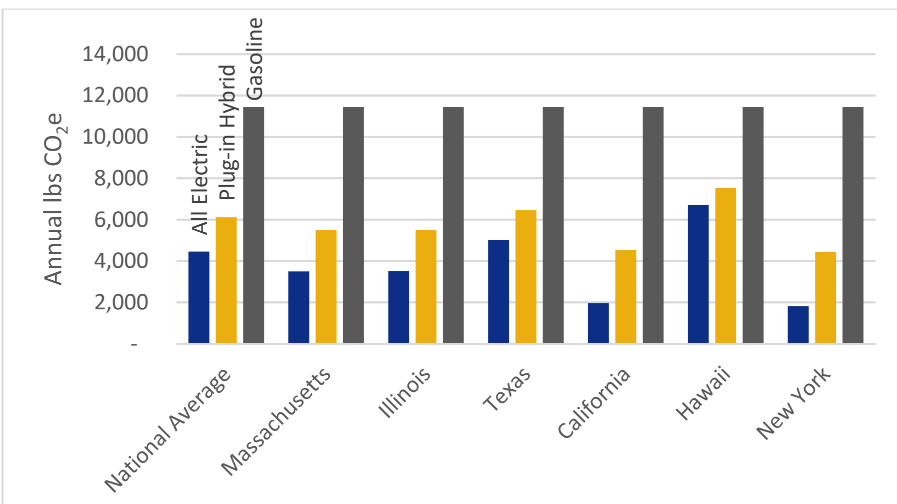
Figure 1. Greenhouse gas emissions by sector in New York



Source: New York Department of Environmental Conservation.

EVs provide a tremendous opportunity to enable New York to meet its greenhouse gas reduction targets and save money at the same time. On average, battery electric vehicles in the United States produce approximately one-third of the greenhouse gas emissions as ICEs. In New York, EVs are even cleaner—battery electric vehicles produce only 16 percent of the emissions of ICE vehicles (see Figure 2).[12]

Figure 2. Emissions from EVs and gasoline powered vehicles



Source: U.S. Department of Energy Alternative Fuels Data Center.

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[10] New York's State Energy Plan established emission reduction targets of 40 percent below 1990 levels by 2030 and 80 percent below 1990 levels by 2050. https://energyplan.ny.gov/.

[11] New York State is one of nine states that have adopted California's ZEV standards. These are incorporated by reference in 6 NYCRR Part 218, specifically Subpart 218-4.1 ZEV Percentages. These standards require automakers to produce a certain percentage of zero emission vehicles to improve air quality and combat climate change.

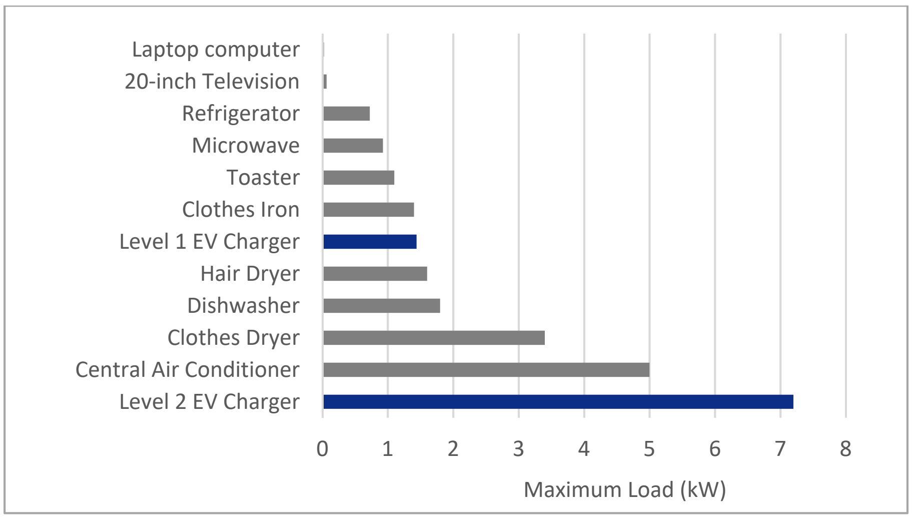
[12] U.S. Department of Energy Alternative Fuels Data Center. 2015. "Emissions from Hybrid and Plug-In Electric Vehicles." Available at: www.afdc.energy.gov/vehicles/electric_emissions.php.

By utilizing existing electricity infrastructure more efficiently, EVs can help lower electricity costs. For example, EVs can help to absorb excess energy from renewables when that energy is plentiful but demand is low, such as during the overnight hours. And by increasing the volume of electricity sold, EVs allow the fixed costs of the grid to be spread over more kilowatt-hours, thereby reducing electricity rates for all customers—regardless of whether the customer drives an EV. As technology evolves, EVs may increasingly provide services back to the grid and operate as "virtual power plants," helping to integrate renewable resources and enhance reliability.[13]

Achieving these benefits depends on (1) charging EVs in a manner that minimizes costs to the grid, and (2) widespread adoption of EVs. This is where electric utility rate design plays a critical role.

EVs are large consumers of electricity. Further, their instantaneous power draw can be significantly higher than any other typical household appliance, as shown in the figure below. In fact, an EV can easily double a household's peak demand when charged with a Level 2 charger.[14]

Figure 3. EV charging load relative to household appliances



Managing peak demand is a key challenge for electric utilities. As the penetration of EVs increases, charging EVs during times of peak demand could exacerbate grid constraints, require the construction of new power plants or transmission and distribution infrastructure, and increase costs for customers.[15]

Maximizing the benefits of transportation electrification also requires that barriers to EV adoption be removed. Certain electric rate structures can pose financial barriers to potential EV customers and

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[13] In the simplest case, EVs can operate as load reducers by temporarily deferring charging when the grid is stressed. But since EVs are essentially mobile batteries, their batteries can be tapped to provide more sophisticated services as well, such as frequency response and other ancillary services historically provided only by large power plants.

[14] A Level 1 charger uses a standard 120-volt outlet and provides approximately 4.5 miles per hour of charging. A Level 2 charger uses a 240-volt outlet and provides approximately 20 miles per hour of charging. DC fast chargers are another, much more expensive option, and they deliver power at 200–600 V_{DC} to provide approximately 240 miles per hour of charging.

[15] Current penetrations of EVs are unlikely to have a material impact on the grid. But as adoption increases, more attention to load management is warranted.

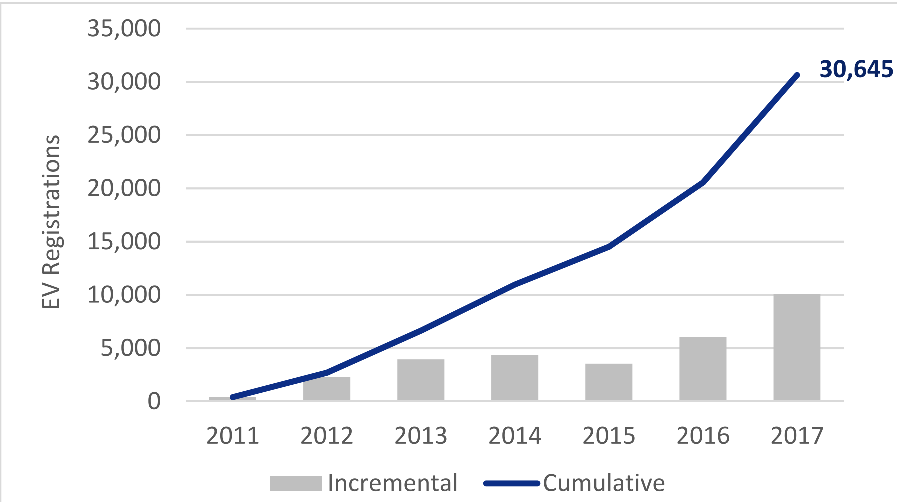
owners of public EV charging stations, thereby reducing demand for EVs and slowing the transition to the cleaner transportation system necessary to meet state goals.

To avoid these pitfalls, electric utilities should provide EV customers with clear electricity price signals to encourage charging off-peak. Further, electricity prices can be used to help encourage the adoption of EVs and support the financial viability of EV charging stations. This report examines best practices in electric vehicle rate design and comments on New York utilities' EV rate design proposals submitted in Docket 18-E-0206.

2. The Case for Effective Rate Design

Electric vehicle adoption in New York is rising rapidly: new EV registrations doubled from 2016 to 2017, as shown in Figure 4. Currently, New York is second only to California in the number of EVs in the United States.

Figure 4. EV growth in New York



Source: Auto Alliance.

At current levels of penetration, EVs could potentially add 215 megawatts (MW) of demand to New York's system if they all charged at the same time using a Level 2 charger. This is nearly equivalent to the total demand reduction expected from current energy efficiency programs.[16] Fortunately, this need not be the case. Because the electricity used to charge an EV's battery is often not immediately used to propel the vehicle, there is generally some flexibility regarding the timing of EV charging. Most drivers do not care when their EVs get charged, as long as the vehicles are ready to drive when needed. This inherent flexibility sets EVs apart from most major residential electricity end-uses (e.g., air conditioning) and opens up the possibility of encouraging efficient charging without inconveniencing consumers.

Given the rapid pace of EV adoption and the potentially large positive or negative impacts that EVs could have on the grid, it is critical that New York set in place a framework that will enable it to integrate EVs into the grid in a low-cost manner and avoid negative grid impacts. Electric utilities can play a prominent role in this regard, as they can provide price signals to customers to encourage EV owners to charge in a manner that is consistent with grid conditions.

[16] NYISO Power Trends, 2017.

Effective EV price signals can:

1) Encourage customer adoption of EVs by maximizing fuel cost savings relative to gasoline or diesel;

2) Lower electricity rates for all utility customers through more efficient grid utilization;

3) Avoid unnecessary grid upgrades by encouraging customers to shift charging to off-peak hours; and

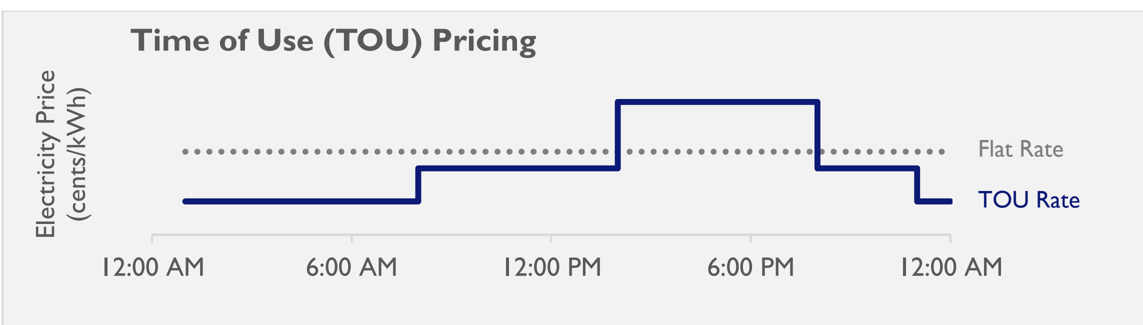
4) Reduce emissions by better aligning charging with renewable energy production.

The following sections discuss effective rate design options.

2.1. Rate Design Options

Standard, time-invariant electricity rates do little to encourage EV adoption or optimal charging times. In fact, these rates may even directly discourage efficient charging practices. Customers are apt to charge when it is most convenient to them, rather than when it is most beneficial to the grid. In contrast, time-varying rates convey price signals that better reflect the cost of producing and delivering energy during different hours. The most common forms of time-varying energy rates are described below, along with a stylized depiction of how each rate could be implemented.

- *Time-of-Use (TOU) Rates:* TOU rates consist of two or more pricing tiers, based on pre-set time periods. Electricity is priced higher during hours when the peak is more likely to occur, and lower during hours that are generally off-peak. An advantage of this type of rate structure is that it has low financial risks to customers, because the pricing is known ahead of time and customers choose whether to curtail their electricity use during on-peak times.

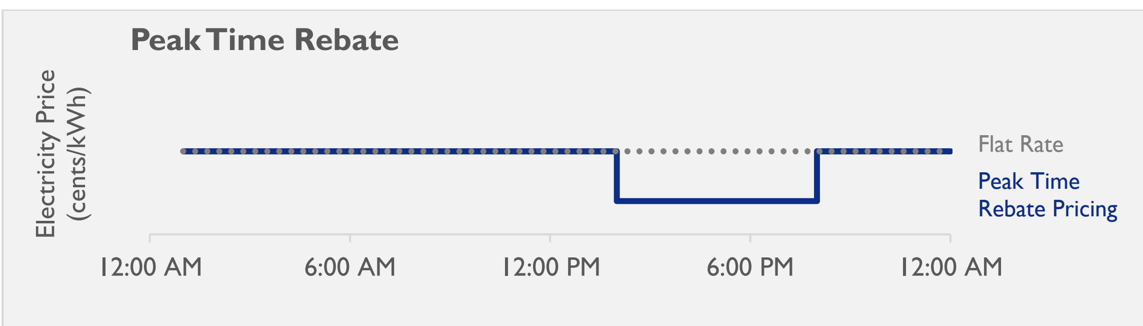


- *Critical Peak Pricing (CPP):* This rate structure is often used in conjunction with TOU rates but can be used with an otherwise flat rate structure as well. Critical peak pricing implements a very high price tier that is only triggered for very specific events, such as system reliability or peak electricity market prices.[17] The timing of the events is

[17] Hledik, R. et al., 2016.

generally not known until a day in advance, and the events typically last for only 2–6 hours.

- *Peak Time Rebates (PTR)*: A peak time rebate program is similar to critical peak pricing, except that customers earn a financial reward for reducing energy relative to a baseline, instead of being subject to a higher rate. As with critical peak pricing, the number of event days is usually capped for a calendar year and is linked to conditions such as system reliability concerns or very high supply prices.[18] While PTR programs tend to be widely accepted by customers, they have two drawbacks relative to critical peak pricing:
    - Baseline usage can be difficult to determine with accuracy. For example, a customer may earn a reward simply because the customer was out of town on the day of the event rather than because the customer actively reduced their electricity consumption in response to the event.
    - Peak time rebates tend to result in lower reductions than critical peak pricing. Customers generally respond more strongly when they are faced with paying more for consumption during peak hours than when they are offered a reward for lowering consumption.

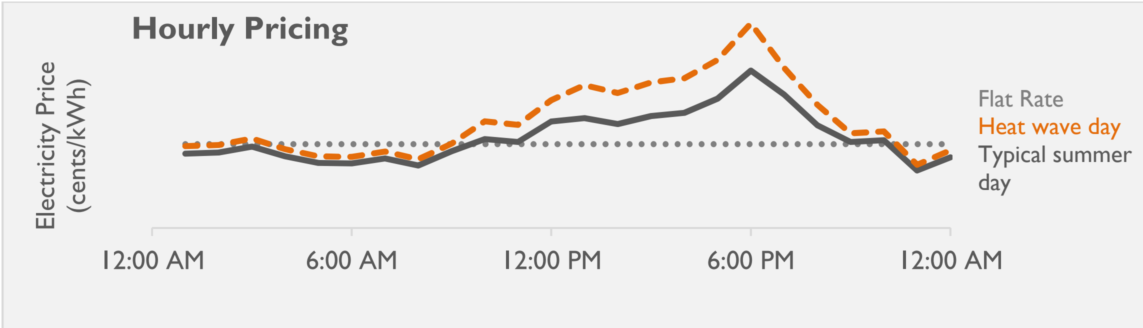


- *Real-Time Pricing and Hourly Pricing:* These rates charge customers for electricity based on the wholesale market price rather than a pre-set rate schedule.[19] Rates fluctuate hourly or in 15-minute increments, reflecting changes in the wholesale price of

[18] United States of America. Federal Energy Regulatory Commission. *Assessment of Demand Response and Advanced Metering.* Washington D.C.: United States, 2010.

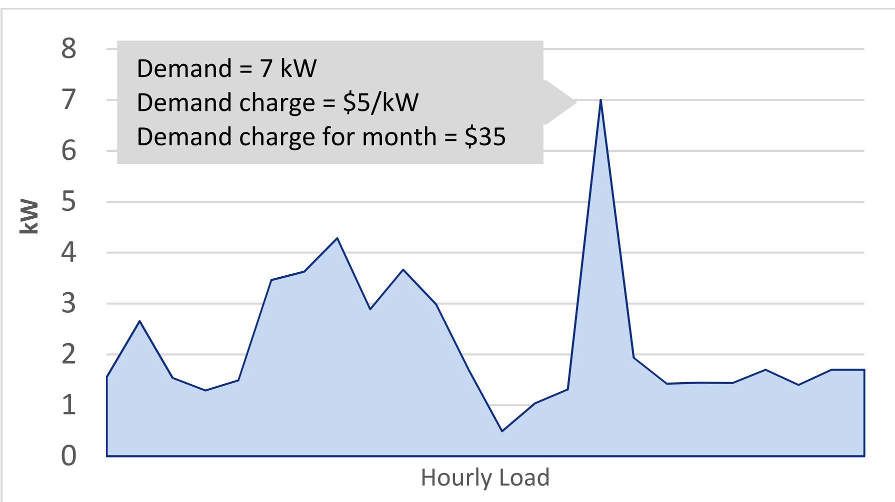
[19] *Id*.

electricity. Customers are typically notified of prices on a day-ahead or hour-ahead basis.



In addition to time-varying energy rates, some utility rates include a demand charge, particularly for large commercial and industrial customers. Instead of assessing a charge based on when and how much energy is consumed (measured in kWh), demand charges are applied to a customer's maximum consumption (measured in kW) during a month.[20] Demand charges can be designed to be time-limited (that, is they only apply during certain peak hours of the day), or they can apply during any hour. Figure 5 illustrates how a demand charge functions.

Figure 5. Hypothetical demand charge example



2.2. Considerations for Rate Design Selection

Overarching Considerations

Each of the above rates has advantages and drawbacks. However, TOU rates are the most popular form of time-varying rate, both for EV customers and non-EV customers. These rates have been offered by

[20] In some cases, demand charges are applied to some measure of a customer's maximum consumption over the course of a year.

utilities for decades and are gaining popularity now that advanced meters are reducing the costs associated with implementation. Results from a survey conducted by the Smart Energy Power Alliance (SEPA) indicate that at least 45 utilities across the country have TOU rates targeted to EVs.[21]

TOU rates are popular for several reasons:

- **Effectiveness:** TOU rates have been shown to be highly effective in shifting EV load.
- **Simplicity:** TOU rates provide an easy-to-understand price signal that reflects general trends in utility costs, without requiring customers to monitor hourly energy prices. TOU rates are particularly well suited to "set it and forget it" technologies, such as the timers on many EV chargers.
- **Efficiency:** TOU rates can be designed by layering different types of utility costs (generation, transmission, and distribution) to reflect the temporal variability of all three.

In contrast, critical peak pricing and peak time rebates only target a few peak hours per year. While such an approach may work well for avoiding additional generation capacity costs, it does not avoid daily higher-cost energy hours. In addition, such rates typically do not reflect the wider range of local distribution peak hours. Another consideration is that the specific hours for critical event days are generally called only a day in advance, making critical peak pricing and peak time rebates less compatible with "set it and forget it" technologies.

Hourly dynamic pricing is an efficient alternative to TOU pricing but is more complex and shifts more risk to customers. Where dynamic pricing is offered, enrollment tends to be low.[22] Further, dynamic pricing may be too variable for public charging stations. In California, the Public Utilities Commission rejected San Diego Gas & Electric's proposed dynamic rate for public charging infrastructure. The Commission wrote, "Dynamic rates are complicated, highly variable, and do not provide enough predictability for drivers that may not be participating in a specific utility program."[23] Instead, the Commission directed the utility to design a TOU rate that provides more predictability for drivers.

Demand charges are even less well-suited to providing price signals that will support EV adoption. In fact, demand charges can work to discourage critical EV charging infrastructure deployment while the EV market is still in early development. Demand charges that apply during any hour of the day effectively become a fixed charge that cannot be avoided by scheduling EV charging for off-peak periods. In the case of workplace and public DC fast charging (DCFC) stations, demand charges can pose

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[21] Erika Myers, Medha Surampudy, and Anshul Saxena, "Utilities and Electric Vehicles: Evolving to Unlock Grid Value" (Smart Electric Power Alliance, March 2018), 24.

[22] For example, only about 17,500 customers out of 3 million have enrolled in Commonwealth Edison's dynamic pricing program. Dick Munson, "Data Reveals Real-Time Electricity Pricing Would Help Nearly All ComEd Customers Save Money," *EDF Energy Exchange* (blog), November 14, 2017, http://blogs.edf.org/energyexchange/2017/11/14/data-reveals-real-time-electricity-pricing-would-help-nearly-all-comed-customers-save-money/.

[23] California Public Utilities Commission, Decision on the Transportation Electrification Priority Review Projects, Decision 18-01-024, Application 17-01-020 et al, January 11, 2018, page 42.

a significant financial disincentive because of the potential to raise customers' bills. Further, demand charges for public charging stations are difficult for the site host to pass on to EV drivers, since the charges billed to the site host are not proportional to utilization by drivers. We discuss this in greater detail in the following section.

Considerations for Public Charging Rates

Rate designs that support, rather than hinder, the development of public charging stations are important for encouraging EV adoption. DCFC stations generally provide power between 50 kW and 350 kW, which enables long-distance electric travel and helps to provide prospective EV drivers with range confidence. Public charging stations are also important for providing charging options for customers in multifamily dwellings or single-family households with on-street parking.[24] In addition, DCFC stations support the electrification of medium- and heavy-duty fleets, such as transit buses, that have intensive duty cycles.

However, most public charging stations are billed on a commercial rate, which typically includes a demand charge. While the electrical demand (kW) at these stations is very high, energy use (kWh) tends to be low due to the limited number of EVs on the road today. This means that the demand charges tend to dominate the electricity bills for these stations. This phenomenon is particularly true for DCFC stations: empirical analysis by Rocky Mountain Institute demonstrated that demand charges can drive over 90 percent of the costs of operating these stations during summer months in California, making it extremely challenging to recoup costs while EV penetration and station utilization are still low.[25]

To illustrate, consider a DCFC station with two 50-kW ports that occasionally has two vehicles charging at once, for a total of 100 kW of demand. Under a high demand charge of $20/kW, the customer would pay a monthly demand charge of $2,000. Under a more moderate demand charge of $6/kW, the monthly demand charge would be $600.[26] While such demand charges may be tenable for future levels of EV penetration, currently many charging stations experience low utilization rates, with some only being used once every few days.

Under the high demand charge case, a charging station with a low utilization rate of one charge every two days (15 charges per month) would have an operating cost of $142 per charging session, equivalent to a cost of $2.84/kWh. At four times the utilization rate (60 charges per month), the cost would fall to only $39 per session (equivalent to a cost of $0.77/kWh).

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[24] Approximately 25 percent of U.S. households live in multifamily dwellings, and approximately 39 percent of single-family households have no access to charging at home. National Research Council of the National Academies, *Overcoming Barriers to Deployment of Plug-In Electric Vehicles* (Washington, DC: National Academies Press, 2015), 85, https://download.nap.edu/cart/download.cgi?record_id=21725.

[25] Garrett Fitzgerald and Chris Nelder, "EVgo Fleet and Tariff Analysis" (Rocky Mountain Institute, April 2017), https://www.rmi.org/wp-content/uploads/2017/04/eLab_EVgo_Fleet_and_Tariff_Analysis_2017.pdf.

[26] Demand charges generally range from $3/kW to $25/kW. In the Northeast, distribution demand charges average approximately $11/kW.

A more moderate demand charge of $6/kW would still result in a cost per session of $49, assuming only 15 charges per month, or $15 per session assuming 60 charges per month. These results are shown in Table 1 below. Such costs would be difficult, if not impossible to recoup from customers under such low utilization.

Table 1. Impact of a demand charge on a charging station with 100 kw demand

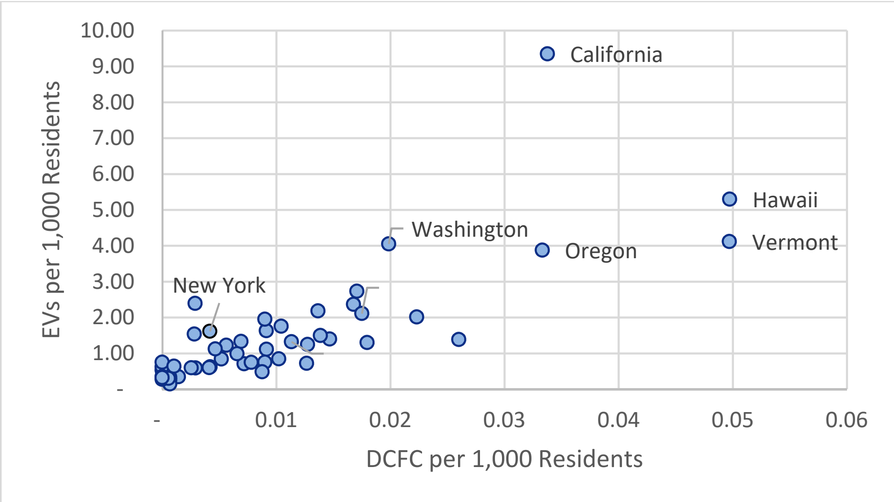
		High Case	Mid Case
Demand Charge ($/kW)		$20	$6
Customer Charge (4/Month)		$70	$70
Energy Charge ($/kWh)		$0.08	$0.08
Energy per Session (kWh)		50	50
15 charging sessions/month	Annual DCFC Bill	$25,560	$8,760
	Cost/session	$142	$49
	Cost/kWh	$2.84	$0.97
60 charging sessions/month	Annual DCFC Bill	$27,720	$10,920
	Cost/session	$39	$15
	Cost/kWh	$0.77	$0.30

To date, DCFC station deployment and EV adoption in New York have been relatively limited. According to data provided by the Alternative Fuels Data Center at the Department of Energy, there are currently 203 DCFC plugs in New York, but only 83 are non-Tesla DCFC plugs.[27] In comparison, there are currently more than 1,300 non-Tesla DCFC plugs in California.[28] The figure below shows the relationship between DCFC and adoption of EVs, controlling for population.

[27] U.S. Department of Energy, Alternative Fuels Data Center, https://www.afdc.energy.gov/data_download, accessed May 2018. Charging stations may contain more than one plug or "port." Often, stations will have two ports. When Tesla charging stations are included, there are 203 in New York compared with 1,775 in California. However, Tesla employs proprietary DCFC charging stations that only Tesla vehicles can access. Therefore, we have focused on charging stations accessible to a wide variety of vehicles.

[28] *Id.*

Figure 6. DC fast chargers (non-Tesla) and EV adoption



Source: Synapse Energy Economics analysis of data from U.S. Department of Energy Alternative Fuels Data Center.

To meet New York's ZEV goal of approximately 800,000 EVs by 2025, many more DCFC will be needed. According to analysis tools developed by the National Renewable Energy Laboratory, New York will require roughly 4,087 DCFC plugs by 2025 to meet its ZEV target.[29]

Where rate design hinders public charging infrastructure, EV adoption is likely to be slow. This begets a chicken-and-egg problem: low levels of EV adoption will result in low charging station utilization and unfavorable business cases for charging station operators, while too few charging stations can slow EV adoption. To address this problem, some utilities have temporarily reduced or eliminated demand charges for customers on EV rates, opting instead to price electricity using TOU rates.

Some have raised concerns that reducing costs for EV charging stations, at least temporarily, could result in cross-subsidization. However, cost shifting will not occur as long as electricity is priced at or above the utility's marginal cost of service.[30] This is because the EV stations are supporting incremental load growth, rather than representing existing load on the system. Existing tariffs are designed to recover embedded costs from existing load, which enables incremental load to be priced at marginal cost, at least during the early years of EV adoption.

[29] To achieve a penetration of 800,000 EVs by 2025, the U.S. Department of Energy's Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite estimates that 4,087 DCFC plugs will be required to meet charging demand in New York, using the assumption that 80 percent of customers have access to charging at home. The tool is available at https://www.afdc.energy.gov/evi-pro-lite. EVI-Pro Lite is a simplified version of EVI-Pro, which was developed through a collaboration between the National Renewable Energy Laboratory and the California Energy Commission, with support from the U.S. Department of Energy. EVI-Pro uses personal vehicle travel patterns, electric vehicle attributes, and charging station characteristics to estimate the charging infrastructure required to support various levels of EV adoption.

[30] Any required distribution upgrades directly related to the charging station should also be recovered from the charging station owner in order to avoid shifting these costs on to other customers.

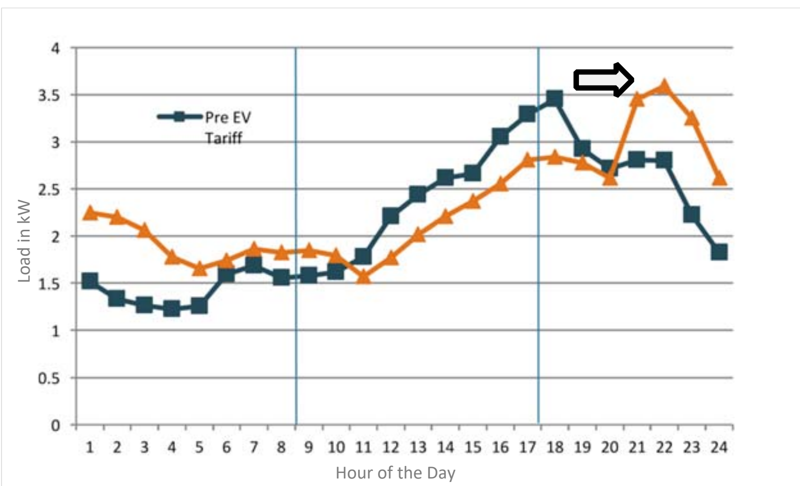
3. Implementation of EV Rates: Lessons from the Field

3.1. Effectiveness of Time-Varying Rates

As noted above, TOU rates have been widely implemented, and in some cases specifically tailored to EV customers. These rates have proven extremely effective in motivating customers to charge off-peak, since customers can save money doing so and off-peak hours generally align with the hours that customers have parked their car at home.

Most TOU rates are applied to all of a customer's load, rather than just the EV load itself. For residential customers, this is referred to as a "whole-house" TOU rate. To test the response of EV customers to such a rate, Baltimore Gas & Electric (BGE) monitored EV customer load before and after enrolling customers in the whole-house TOU tariff. As the graph below shows, without the tariff, customer load peaked at approximately 6 pm, likely when customers returned home from work and plugged in their vehicles. Once customers received the TOU price signal, average load dropped and the peak shifted to the night-time hours.

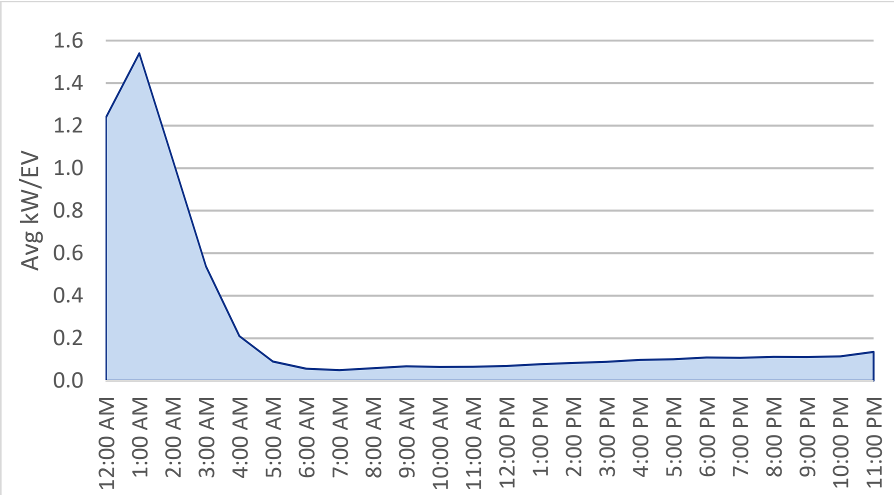
Figure 7. Results of BGE EV tariff pilot



Note: Average weekday customer load before (blue squares) and after (orange triangles) BGE's pilot.
Source: BGE Electric Vehicle Off Peak Charging Pilot, presentation by John Murach, 2017.

The shift in peak load is even more evident for customers on separately metered EV-only rates. For example, under San Diego Gas & Electric's (SGD&E) EV-only rate, the vast majority of load occurs during the middle of the night, as shown in the graph below.

Figure 8. Average load profile for SDG&E customer on EV-only rate



Source: SDG&E Data Response to NRDC DR02-Q6, A.17-01-021.

Both whole-house and EV-only TOU rates have been implemented at all three of California's large IOUs and have been extremely successful in motivating customers to avoid charging on-peak. At Pacific Gas & Electric, 93 percent of charging on the EV-only rate occurs during off-peak hours, while at Southern California Edison, 88 percent of charging is off-peak.[31]

3.2. Design of TOU Rates

Price Ratios

To ensure an effective TOU rate design, the ratio between peak and off-peak prices must be sufficient to motivate customers to shift their load. A study of early-adoption EV customers in SDG&E's service territory found that a peak to off-peak price ratio of 6:1 results in about 10 percent more off-peak charging than a ratio of 2:1.[32]

Reflecting Generation, Transmission, and Distribution Costs

Despite the fact that approximately half of the EVs in the United States are located in California, very few costly grid upgrades due to EVs have occurred to date. According to reports filed by the utilities, grid upgrades due to EVs have totaled less than 0.01 percent of distribution capital costs.[33] This is likely due, at least in part, to the time-varying rates offered by all three of California's IOUs.

[31] Synapse Analysis of Joint Utilities Load Research Report, Dec 2017.

[32] Nexant. 2014. "Final Evaluation of SDG&E Plug-in Electric Vehicle TOU Pricing and Technology Study." Available at www.sdge.com/sites/default/files/documents/1681437983/SDGE%20EV%20%20Pricing%20&%20Tech%20Study.pdf.

[33] *Id.*

To be efficient, time-varying rates must reflect grid costs. One way in which this is done is by assigning marginal generation, transmission, and distribution costs to each hour of the year. For capacity, this can be done using loss of load expectations for each hour of the year, while for energy, the costs are based on the variable operating costs of different power plants.

The tables below show "heat maps" that reflect hourly marginal costs (in terms of dollars per kWh) for a California utility. The months are shown on the vertical axis, while the hours of the day are shown along the horizontal axis. When the heat maps are combined (Figure 12), the areas of high and low costs can be used to set TOU windows and price differentials.

Figure 9. Marginal energy costs

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	0.049	0.048	0.047	0.047	0.048	0.050	0.058	0.062	0.049	0.046	0.045	0.044	0.041	0.042	0.043	0.046	0.057	0.081	0.077	0.071	0.063	0.060	0.055	0.051
February	0.048	0.047	0.047	0.047	0.048	0.050	0.059	0.053	0.047	0.044	0.043	0.043	0.042	0.042	0.043	0.044	0.049	0.067	0.076	0.073	0.065	0.060	0.054	0.050
March	0.047	0.046	0.046	0.046	0.046	0.047	0.052	0.049	0.045	0.040	0.037	0.032	0.027	0.030	0.038	0.040	0.042	0.050	0.062	0.079	0.069	0.061	0.056	0.049
April	0.046	0.044	0.044	0.044	0.045	0.047	0.051	0.044	0.040	0.035	0.032	0.030	0.028	0.029	0.036	0.038	0.040	0.044	0.050	0.069	0.071	0.058	0.052	0.047
May	0.046	0.045	0.044	0.044	0.045	0.047	0.047	0.043	0.039	0.037	0.037	0.037	0.036	0.037	0.038	0.040	0.041	0.045	0.047	0.063	0.071	0.062	0.054	0.048
June	0.047	0.045	0.045	0.045	0.046	0.047	0.046	0.042	0.039	0.038	0.038	0.039	0.038	0.039	0.040	0.042	0.044	0.050	0.048	0.065	0.074	0.070	0.057	0.049
July	0.049	0.046	0.045	0.045	0.045	0.047	0.046	0.043	0.040	0.041	0.042	0.044	0.046	0.049	0.053	0.056	0.060	0.073	0.059	0.096	0.079	0.070	0.060	0.053
August	0.049	0.047	0.046	0.046	0.046	0.048	0.050	0.045	0.043	0.042	0.042	0.043	0.044	0.046	0.049	0.053	0.060	0.074	0.065	0.092	0.080	0.067	0.059	0.053
September	0.049	0.047	0.046	0.046	0.046	0.049	0.055	0.049	0.044	0.042	0.042	0.042	0.043	0.045	0.048	0.050	0.057	0.073	0.090	0.106	0.074	0.062	0.057	0.051
October	0.048	0.047	0.046	0.046	0.046	0.048	0.054	0.054	0.045	0.042	0.041	0.041	0.042	0.043	0.045	0.046	0.048	0.062	0.073	0.079	0.067	0.060	0.056	0.050
November	0.049	0.047	0.047	0.047	0.047	0.049	0.055	0.050	0.046	0.044	0.044	0.043	0.043	0.044	0.045	0.048	0.061	0.089	0.076	0.068	0.063	0.059	0.054	0.050
December	0.050	0.048	0.048	0.048	0.048	0.050	0.057	0.057	0.049	0.047	0.046	0.046	0.045	0.045	0.046	0.048	0.060	0.084	0.077	0.073	0.066	0.062	0.059	0.052

Figure 10. Marginal generation capacity costs

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	-	-	-
June	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.002	0.004	0.007	0.010	0.165	0.164	0.009	-	-
July	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.000	0.000	0.000	0.011	0.031	0.002	-	-
August	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.003	0.008	0.007	0.054	0.621	0.214	0.004	-	-
September	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.003	0.023	0.107	0.249	2.665	1.789	0.441	0.019	0.000	-
October	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.000	0.004	0.011	0.002	0.000	0.000	0.000	-
November	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Figure 11. Marginal distribution capacity costs

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	0.002	0.001	0.001	0.001	0.001	0.003	0.007	0.006	0.006	0.005	0.003	0.002	0.003	0.003	0.004	0.006	0.006	0.024	0.018	0.015	0.010	0.007	0.008	0.005
February	0.002	0.001	0.001	0.001	0.001	0.002	0.006	0.007	0.006	0.005	0.004	0.004	0.004	0.005	0.004	0.005	0.006	0.014	0.015	0.013	0.008	0.007	0.007	0.005
March	0.002	0.000	0.001	0.001	0.000	0.002	0.005	0.005	0.004	0.002	0.003	0.002	0.002	0.002	0.003	0.004	0.006	0.008	0.010	0.010	0.010	0.008	0.006	0.004
April	0.002	0.001	0.001	0.001	0.001	0.001	0.004	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.003	0.003	0.006	0.011	0.008	0.010	0.009	0.009	0.007	0.005
May	0.004	0.001	0.001	0.001	0.001	0.001	0.003	0.003	0.003	0.002	0.002	0.003	0.003	0.003	0.004	0.006	0.009	0.020	0.013	0.015	0.016	0.012	0.008	0.006
June	0.005	0.002	0.001	0.001	0.002	0.001	0.002	0.003	0.003	0.005	0.004	0.006	0.004	0.008	0.010	0.016	0.020	0.028	0.020	0.021	0.022	0.021	0.017	0.010
July	0.009	0.005	0.003	0.002	0.003	0.004	0.007	0.007	0.009	0.009	0.012	0.013	0.012	0.019	0.025	0.029	0.043	0.088	0.060	0.043	0.036	0.032	0.024	0.015
August	0.011	0.005	0.003	0.003	0.003	0.006	0.009	0.008	0.009	0.011	0.013	0.014	0.016	0.024	0.031	0.049	0.071	0.095	0.065	0.047	0.040	0.032	0.025	0.017
September	0.007	0.003	0.002	0.002	0.002	0.004	0.010	0.008	0.008	0.009	0.010	0.011	0.015	0.019	0.026	0.040	0.059	0.101	0.044	0.046	0.036	0.025	0.021	0.015
October	0.003	0.001	0.000	0.001	0.001	0.003	0.005	0.005	0.005	0.004	0.004	0.004	0.003	0.006	0.008	0.015	0.022	0.039	0.024	0.030	0.017	0.011	0.008	0.006
November	0.002	0.001	0.001	0.001	0.001	0.002	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.006	0.006	0.009	0.045	0.024	0.014	0.009	0.007	0.007	0.005
December	0.003	0.001	0.001	0.001	0.001	0.003	0.006	0.006	0.006	0.005	0.004	0.004	0.003	0.004	0.005	0.006	0.007	0.041	0.025	0.019	0.013	0.009	0.008	0.006

Figure 12. Total marginal costs

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	0.051	0.049	0.048	0.048	0.049	0.053	0.069	0.078	0.055	0.050	0.048	0.046	0.044	0.045	0.047	0.057	0.099	0.169	0.115	0.086	0.074	0.067	0.063	0.056
February	0.050	0.048	0.047	0.048	0.049	0.052	0.064	0.060	0.053	0.049	0.047	0.047	0.046	0.047	0.047	0.051	0.084	0.162	0.133	0.086	0.072	0.067	0.061	0.055
March	0.049	0.046	0.046	0.046	0.046	0.049	0.057	0.054	0.049	0.042	0.039	0.034	0.029	0.033	0.041	0.044	0.065	0.131	0.155	0.103	0.078	0.070	0.062	0.053
April	0.048	0.045	0.045	0.045	0.046	0.048	0.055	0.047	0.042	0.036	0.033	0.032	0.030	0.031	0.039	0.041	0.046	0.102	0.170	0.087	0.080	0.067	0.059	0.052
May	0.050	0.046	0.045	0.045	0.046	0.049	0.050	0.046	0.042	0.039	0.039	0.039	0.039	0.040	0.043	0.045	0.050	0.106	0.156	0.088	0.087	0.073	0.062	0.054
June	0.052	0.047	0.046	0.046	0.047	0.049	0.048	0.046	0.043	0.044	0.044	0.045	0.043	0.047	0.051	0.059	0.066	0.112	0.157	0.215	0.194	0.097	0.074	0.059
July	0.058	0.051	0.048	0.047	0.048	0.050	0.053	0.050	0.049	0.050	0.054	0.057	0.058	0.068	0.077	0.086	0.102	0.203	0.218	0.145	0.134	0.103	0.084	0.068
August	0.060	0.052	0.049	0.049	0.049	0.054	0.058	0.053	0.052	0.053	0.055	0.057	0.059	0.070	0.080	0.104	0.146	0.235	0.249	0.511	0.248	0.101	0.084	0.070
September	0.056	0.050	0.048	0.048	0.048	0.052	0.065	0.057	0.052	0.051	0.052	0.054	0.058	0.064	0.076	0.104	0.185	0.381	1.844	1.225	0.374	0.099	0.079	0.066
October	0.051	0.048	0.047	0.047	0.047	0.051	0.060	0.062	0.050	0.045	0.045	0.045	0.046	0.049	0.052	0.061	0.089	0.180	0.173	0.111	0.084	0.071	0.064	0.056
November	0.050	0.048	0.048	0.048	0.048	0.051	0.060	0.055	0.050	0.048	0.048	0.047	0.047	0.048	0.051	0.079	0.157	0.200	0.099	0.082	0.072	0.065	0.061	0.056
December	0.053	0.049	0.048	0.049	0.049	0.054	0.063	0.063	0.055	0.051	0.050	0.050	0.049	0.049	0.051	0.054	0.122	0.255	0.107	0.092	0.080	0.072	0.067	0.058

When designing TOU rates, it can be instructive to examine distribution costs on a class level as well. In some cases, commercial areas peak during the middle of the days, while circuits serving residential customers peak in the evening. Such findings may suggest establishing different on-peak and off-peak periods for different customer classes.

Another consideration is how wide to set each on-peak and off-peak window. Narrow peak periods and wide off-peak periods provide customers with the most flexibility to shift energy consumption to off-peak hours, but care must be taken to avoid creating a new peak by shifting load to immediately before or after the peak period window.[34] Narrow off-peak windows concentrate energy consumption, which can be problematic when this occurs with large EV loads clustered in small areas. Because EV adoption tends to occur in certain neighborhoods and regions more than others, areas with high penetrations of EVs could see local spikes in demand when all EVs begin charging simultaneously. To avoid this, longer off-peak periods can be beneficial.

3.3. Alternatives to Demand Charges

As noted above, demand charges can be a barrier to both DCFC as well as workplace charging. For this reason, some utilities have proposed to reduce the demand charge for these customers, or to temporarily suspend the demand charge (instead shifting the cost recovery to the energy charge). For example, in California, Southern California Edison proposed to exclude a demand charge from its EV rate designs. Instead, it is recovering costs through TOU rates for a period of five years. The demand charge would then be gradually phased back in over the next five years. Similarly, in New York, the Consolidated Edison Company of New York's (Con Edison) proposed to provide a temporary discount to public fast charging stations (with an aggregate capacity of at least 100 kW) through its Business Incentive Rate program. This program reduces customers' delivery charges by nearly 40 percent for a period of up to seven years.[35] The New York Public Service Commission approved this discount, noting the importance of publicly available EV charging stations in supporting adoption of EVs. The Commission also stated that the discount would "help mitigate the high cost of EV charging station operation in an immature market with low charging station utilization."[36]

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[34] To mitigate the sharp rise in demand at the beginning of the off-peak period, some utilities are exploring managed charging. Managed charging would allow a utility (or third party) to remotely reduce the rate of vehicle charging in a manner similar to traditional demand response programs. However, the cost of the communications infrastructure necessary to relay such signals may be cost prohibitive. *See:* Erika Myers, "Utilities and Electric Vehicles: The Case for Managed Charging" (Smart Electric Power Alliance, April 2017), 5, https://sepapower.org/resource/ev-managed-charging/. In some cases, utilities assign customers a specific time to start charging to avoid a sudden surge in demand. Conversation with Pasi Miettinen, President and CEO of Sagewell, Inc.

[35] To be eligible, customers must not impose substantial additional distribution facility costs on the system, unless those costs are borne by the customer.

[36] New York Public Service Commission, Order Approving Tariff Amendments, Case 17-E-0814, April 24, 2018, page 6.

3.4. Metering Technologies for EV-Only Rates

Customers may be hesitant to enroll in a whole-house TOU rate plan because it can be a challenge to shift certain energy-intensive behaviors from expensive on-peak periods to cheaper off-peak periods. It is much easier for customers to monitor and control EV charging than appliances in other parts of the home. For this reason, customers may prefer an EV-only TOU rate to a whole-house rate.

While customers on a whole-house TOU rate plan would only need a single meter to monitor electricity use, EV-only rates require a separate revenue-grade meter or the use of submetering technology to record electricity use that is specifically attributable to EV charging. Each metering option has certain advantages and drawbacks. While a second utility meter is a straightforward option, the costs of installation can be prohibitively high, and customer charges associated with a second meter can deter customers. Submetering is promising, particularly if installation costs can be reduced further and data transfer issues can be resolved. We discuss these and other metering options below.

Second Meter for EV Charging

Standard utility practice for EV-only rate plans is to combine TOU rates with the installation of a second meter designated specifically to monitor EV charging. Some utilities provide the EV billing meter free of charge while others require that customers pay for it through an up-front fee or additional monthly charge. Although a second meter makes it easy to apply TOU rates only to EV charging, the additional meter and installation charges present a significant barrier to widespread adoption of EV-only rates.

Regardless of who pays for the second meter, customers are generally responsible for the installation costs, which include the meter socket(s) with a lever bypass and conduit and wiring performed by an electrician. The installation can cost thousands of dollars up front for customers, eliminating virtually any of the fuel cost savings associated with the EV-only rate. The Minnesota Public Utilities Commission notes that residential customers typically spend between $1,725 and $3,525 on electrical wiring and metering costs to enroll in Xcel Energy's current EV tariff.[37]

As a result of the high costs associated with separately metered programs, enrollment has been low to date in many jurisdictions.[38] For example, as of April 2017, Xcel Energy (Minnesota) had only enrolled 95 customers on its second-meter EV rate over the course of nearly two years.[39] In recognition of these

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[37] Minnesota Public Utilities Commission, Order Approving Pilot Program, Granting Variance, and Requiring Annual Reports. Docket No. E-002/M-17-817, May 9, 2018, page 2.

[38] Utilities offering second-meter EV rates include Southern California Edison, PG&E, SDG&E, Detroit Edison, Consumers Energy, Xcel MN, and Dominion Energy.

[39] Minnesota Public Utilities Commission Staff, Briefing Papers, In the Matter of Xcel Energy – Electric – Petition for Approval of a Residential EV Service Pilot Program, E002/M-17-817, April 12, 2018, page 14.

barriers to enrollment, Xcel has initiated a submetering pilot to attempt to reduce costs and provide additional options to customers.[40]

In a similar case, Dominion Power had to extend its pilot EV pricing plan due to low enrollment. Dominion's pilot consists of two EV pricing plan options: an EV-only TOU rate and a whole-house TOU rate. The EV-only rate requires a separate meter, while the whole-house TOU rate requires an upgraded meter that is capable of recording interval usage. Dominion provides the meters to customers at no charge, but customers are responsible for the installation costs. [41] Customers on the EV-only rate also face an additional monthly customer charge.

Dominion's pilot was originally approved by the Virginia State Corporation Commission in 2011 with an enrollment limit of 1,500 participants. As of October 2013, the pilot program had 230 enrolled participants, but Dominion noted that EV adoption levels in its service territory had grown by more than 700 percent over the course of the original program.[42] The Commission approved the extension to allow more time for the pilot to reach full enrollment and to enable Dominion to more fully analyze the results. In 2016, five years after commencement, the pilot closed enrollment at only 600 customers – less than half of the cap.

Both of these examples illustrate the magnitude of the cost barrier associated with using a second meter to provide EV rates. Because the cost of installing the second meter can be such a deterrent, utilities and regulators have started to seek other options, such as submetering. Submetering offers much promise, but currently faces cost challenges of its own. Another option is to utilize the metering equipment in the EV itself (on-board metering), but this has not been explored to the same extent as other forms of submetering.

Submetering Technologies

Submetering is similar to having an additional meter, except that the submeter is located between the primary meter and the EV. This allows the EV load to be billed on a time-varying rate, while the rest of the household usage is billed on a standard rate. Submeters are not yet widely used for EV-only tariffs, but California has conducted extensive testing on the technology, and several utilities are piloting

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[40] Xcel Energy, In the Matter of Xcel Energy – Electric – Petition for Approval of a Residential EV Service Pilot Program, E002/M-17-817, November 17, 2017.

[41] Under the EV-only rate, a dedicated hard-wired circuit is required, and an electrician may recommend changes to the existing electrical set up, which would incur additional costs. Under the whole-house TOU rate, service upgrades may be required due to the additional energy consumed at a home, which would incur additional costs from an electrician.

[42] Rivera-Linares, Corina. 2013. Dominion Virginia Power seeks to extend electric vehicle pilot program by two years. TransmissionHub. Available at: https://www.transmissionhub.com/articles/2013/11/dominion-virginia-power-seeks-to-extend-electric-vehicle-pilot-program-by-two-years.html

submetering for EV tariffs.[43] The current technology options and costs associated with submeters include:

1) Stand-alone submeters like the WattBox™ from eMotorWerks, with a cost of approximately $250;[44]

2) Submeters integrated with the EV supply equipment ("EVSE," colloquially "charging station"). At-home EVSE are generally Level 2 charging stations such as the JuiceBox™ from eMotorWerks with a cost of approximately $899,[45] or the ChargePoint Home from ChargePoint with a cost of approximately $674;[46] and

3) Mobile (in-car) submeters such as the FleetCarma C2 device.

Installation of both stand-alone and EVSE-integrated submeters typically requires an electrician and will incur an additional cost. In contrast, FleetCarma's C2 device is "plug-and-play," allowing the EV owner to simply plug it into the on-board diagnostics port found under the dash of the vehicle. All three submeter types collect EV charging data and use WiFi or a cellular network to record and transmit usage data to third-party vendors or directly to the utility.

California has actively sought to promote the development of submetering technologies as a lower cost option to traditional metering options. To that end, a two-phase multi-year pilot was initiated in California to test submetering functionality. The two-phase pilot ran from 2014 to 2018 and provided opportunities to identify submetering challenges and work to overcome those barriers. In addition to California's pilot, EVSE-embedded submetering has been implemented for EV off-peak charging rewards at Belmont Light in Massachusetts and will be soon be tested in Minnesota. Mobile (in-car) submeters are currently in use for Con Edison's Smart Charge Rewards program and have also been used for pilot in Toronto and Arizona.[47]

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[43] California is in Phase II of its submetering pilot, while Xcel Minnesota recently obtained approval to proceed with its submetering pilot. Submetering has also been tested by some municipal utilities, such as Belmont Light in Massachusetts.

[44] Cook, J. et al. 2016. California Statewide PEV Submetering Pilot – Phase 1 Report. Nexant. Prepared for the California Public Utilities Commission. Page 31.

[45] Pricing as of May 2018 on eMotorWerks website store: https://emotorwerks.com/store/residential/juicebox-pro-75-smart-75-amp-evse-with-24-foot-cable?gclid=CjwKCAjw_47YBRBxEiwAYuKdw3px-uQc2d5KVUzQHr-KOnLCI3sNmkUyDNm6e6VifNu-PrYt15dCmhoCtM8QAvD_BwE

[46] Pricing as of May 2018 on ChargePoint website store: https://store.chargepoint.com/chargepoint-home

[47] Toronto's program is called ChargeTO, and the results of its pilot are available from FleetCarma here: https://www.fleetcarma.com/resources/chargeto/. The Salt River Project's pilot results are available here: https://www.srpnet.com/newsroom/releases/011018.aspx.

Stand-Alone and Embedded EVSE Submetering

Technical Challenges and Progress

Several submetering pilot programs have noted issues with data transmission associated with WiFi, which can result in problems with customer bills. Almost all of the participants in Phase 1 of California's Plug-In Electric Vehicle Submetering Pilot, which ran between 2014 and 2016, used stand-alone submeters with WiFi for data transmission. A common problem was spotty data coverage, submeters going offline, and software issues with data server. Analysis of a sample of submeters in use suggested that 10–20 percent experienced some sort of data accuracy problem over the course of the Phase 1 Pilot.[48]

Belmont Light in Massachusetts reported a similar experience, stating that it was unable to provide accurate rebates to customers for off-peak EV charging due to WiFi connectivity and data access issues with stand-alone submeters.[49] However, participants with EVSE embedded submeters did not report the same data issues.[50] Belmont Light was also able to verify customer charging via smart meter data, whereas the California utilities reviewed program data from third-party Submeter Data Management Agents, who measured EV electricity use and delivered data to the utilities on a daily basis for billing purposes.

The California Phase 1 submetering pilot was a relatively small-scale pilot with only 241 participating customers. Phase 2, which began in January 2017 and concluded in April 2018, was designed to address some of the issues encountered in Phase 1 and test even more stringent levels of metering accuracy. For example, the accuracy threshold for submeters was lowered from 5 percent to 1 percent for Phase 2, as recommended in the Phase 1 evaluation report.[51] This threshold eliminates most of the stand-alone submetering technologies and requires the use of a submeter integrated with the EVSE.

In addition to the submetering pilot, SDG&E plans to deploy 3,500 EVSE with embedded submeters for its *Power Your Drive* vehicle-to-grid integration pilot and up to 60,000 EVSE with embedded submeters for its residential charging program.[52] Currently vendors are undergoing multi-month testing to ensure that the EVSE can provide dynamic, hourly rates (on a day-ahead basis) to the driver, allow the customer to set charging needs, and collect and transmit the hourly usage data to the utility.[53] These advanced

[48] Cook, J. et al. 2016. California Statewide PEV Submetering Pilot – Phase 1 Report. Nexant. Prepared for the California Public Utilities Commission. Page 12.

[49] Conversation with Rebecca Keane, Energy Resources Analyst at Belmont Light. April 26, 2018.

[50] Conversation with Rebecca Keane, Energy Resources Analyst at Belmont Light. April 26, 2018.

[51] Jonathan Cook et al., "California Statewide PEV Submetering Pilot – Phase 1 Report.," Prepared for the California Public Utilities Commission (Nexant, April 1, 2016), 13.

[52] California Public Utilities Commission, Decision on Transportation Electrification Standard Review Projects, Decision 18-05-040, May 31, 2018.

[53] SDG&E. Electric Vehicle-Grid Integration Pilot Program ("Power Your Drive") Third Semi-Annual Report of San Diego Gas & Electric Company, Rulemaking 13-11-007, September 19, 2017.

technical requirements have required that EVSE vendors develop custom software solutions, and they will certainly help to further the state of the technology.

EVSE-Embedded Submetering Costs

Although submetering is intended to lower costs to customers, there are often substantial costs associated with installation for submeters embedded in Level 2 EVSE. These costs can be a deterrent to drivers. In California, Nexant found that installation costs must be kept low and charging savings must be approximately $15/month, on average, to be attractive to EV owners. Increasing the installation costs of a submeter by $150 reduced the likelihood of program enrollment by one-third, while an increase of $300 reduced the likelihood of enrollment by one-half.[54]

Cost issues were less important for Belmont Light, where many of its customers that participated in the pilot program already had Level 2 chargers that could be integrated with smart meters to provide EV charging data to the utility. These customers received a rebate from the utility of $5/month in exchange for a promise to shift charging to off-peak hours. (Note that Belmont Light does not currently have TOU rates.) Customers were allowed up to three charges per month during on-peak times to retain this incentive.[55]

Mobile Submeters

Mobile (in-car) submeters offer another option for utilities to gather information on the charging and driving patterns of EV owners. Con Edison currently offers an off-peak charging incentive program to EV customers using the FleetCarma C2 device, which is installed by plugging it into the vehicle's on-board diagnostics port. The device then collects vehicle charging and driving data by decoding signals from the vehicle's internal computer system and sends the data securely to FleetCarma servers over the cellular network.

Rather than apply a TOU rate structure, the SmartCharge NY program rewards participants with e-gift cards for off-peak charging behavior anywhere in the Con Edison service territory (EV owners do not have to be Con Edison customers).[56] Con Edison launched the program in April 2017 with 100 EVs with the C2 device. The program was expanded to full scale in July 2017, and then in September 2017 the *Bring Your Own Charger Fleet Program* component was launched. As of January 2018, there were 875 EVs enrolled in the program (431 private EVs and 444 New York City electric fleet vehicles), representing

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[54] Cook et al., "California Statewide PEV Submetering Pilot – Phase 1 Report.," 10.

[55] Going forward, Belmont Light has combined its customers into one group and increased its incentive to $8/month for off-peak charging. Conversation with Rebecca Keane, Energy Resources Analyst at Belmont Light. April 26, 2018.

[56] Sherry Login, "SmartCharge New York," January 22, 2018, 4, http://www.state.nj.us/bpu/pdf/publicnotice/stakeholder/20180205/NJ%20EV%20Stakeholders%20Meeting_January%2022%202018%20Con%20Ed.pdf.

15 percent of the EVs in Con Edison's service territory. By charging off-peak, Con Edison estimates the program has achieved a 0.63 MW peak load reduction.[57]

Through the use of a mobile submeter and rewards program, SmartCharge NY avoids the need for electricians or utility crews to install equipment, does not require a separate EV tariff, does not require complex billing processes, and avoids additional customer charges from the utility. The rewards offered for off-peak charging may also be updated as needed with no filing requirements, and EV owners do not have to be utility account holders.[58] Importantly, Con Edison has found that SmartCharge NY has higher enrollments than its TOU programs, with 875 vehicles enrolled in nine months. In contrast, the TOU Rate with one-year price guarantee had 55 customers enrolled over the course of four years, and the EV-only TOU rate program has only four customers enrolled.[59]

A key drawback of this technology and program type is its cost. Based on program data provided by Con Edison, the annual non-incentive costs of the program total approximately $250 per year per EV customer enrolled.[60] In other jurisdictions with lower enrollments, the non-incentive costs have been estimated to be many times higher.[61] Other challenges to greater program enrollment include: customer awareness, privacy concerns (FleetCarma attempts to manage this issue by anonymizing the data provided to utilities), difficulties installing the C2 device in Tesla vehicles, and the limitation to light-duty vehicles.[62] Next steps for the SmartCharge NY program include a four-month pilot program evaluating the viability of cloud-based technology as an alternative to the C2 device.[63]

On-Board Metering

On-board metering (or "on-vehicle metering") could offer a low-cost alternative submetering approach but requires more testing and support to mature. By using the vehicle's built-in metering and telemetry capabilities, on-board metering could avoid the need for a separate, external device and communications infrastructure altogether. In comments filed in California, GM stated "On-vehicle metering is a consideration that could provide the most cost-effective, communications capable,

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[57] Login, 16.

[58] Login, 18.

[59] Information on TOU rates can be found at: https://www.coned.com/en/save-money/energy-saving-programs/time-of-use.

[60] Login, 3.

[61] For example, NV Energy's estimated administrative cost for the program totaled approximately $1,400 per customer. This high cost is likely related to the small scale of NV Energy's proposed program, which would only provide incentives to 300 EV customers. *See:* Direct Testimony of Will Toor on behalf of Nevadans for Clean Affordable Reliable Energy, Docket 18-02002, May 8, 2018, page 11.

[62] *Id*. Slide 19.

[63] *Id*. Slide 20.

regulatory compliant and utility/customer friendly solution for measuring and recording BEV and PHEV electricity consumption."[64]

Although the potential for on-board metering has been noted both in the United States and abroad, it has yet to gain widespread attention or adoption, except for in specific applications such as aggregated demand response. A key barrier to the use of on-board metering for implementing time-varying rate structures is the requirement for revenue grade metering and the implications for billing responsibility. Specifically, metering requirements generally follow American National Standards Institute (ANSI) standards for metering accuracy of +/- 0.2% or +/- 0.5% and require rigorous testing and certification processes. Further, resolution of billing disputes where submeters are involved can be complicated.[65]

To overcome these barriers, the need for stringent metering standards for submetering may need to be revisited and clear rules for dispute settlement established. California's submetering protocol proceedings and pilots are currently exploring some of these issues. However, they primarily focus on embedded EVSE submetering, rather than on-board vehicle metering.[66]

While on-board metering has not been developed to the point where it is used for traditional rate structures, it is being used or piloted for applications where metering requirements are less onerous. These applications include providing demand response where the performance of multiple EVs are aggregated together and rebate programs that provide customers with rewards (such as gift cards) for off-peak charging outside of the traditional utility billing process.[67]

3.5. Maximizing Customer Enrollment in EV Rates

Low levels of customer enrollment in EV rates can prevent achievement of the substantial benefits associate with TOU rates. Enrollment levels can be low due to several reasons, including:

- Rates that are too complex to be easily understood by customers,
- Customer inertia (the "hassle factor"),
- Lack of awareness of the rate, and
- Uncertainty regarding whether customers will save money on the new rate.

As discussed in Chapter 0, TOU rates are the most widespread time-varying rate in use today, in part because of their simplicity and customer acceptance. Sometimes TOU rates are combined with critical peak pricing to provide even more targeted price signals, which has also been successful. Although there

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[64] GM. Comments in response to Rulemaking (R.) 09-08-009 "The Utility Role in Supporting Plug-In Electric Vehicle Charging" Staff Issues Paper, August 30, 2010.

[65] Communication with George Bellino, June 7, 2018.

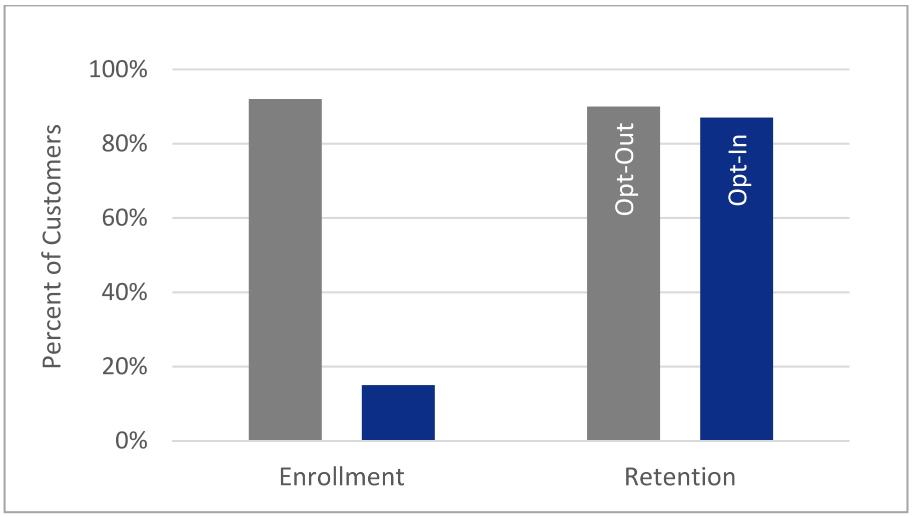
[66] California's submetering pilot program documents are available at http://www.cpuc.ca.gov/general.aspx?id=5938.

[67] The authors understand that Con Edison is currently exploring on-board metering for its off-peak rebate programs.

is theoretical appeal in more dynamic rates (such as those that vary by hour or by location), such rate designs are generally too complex for residential customers and likely to lead to low enrollment.[68]

Due to customer inertia, low levels of customer enrollment are common when customers are required to actively opt-in to the rate, but high levels of customer enrollment can be achieved through defaulting customers onto a rate (through an opt-out design). This has been found to be true for both EV customers and non-EV customers. For example, an analysis of 10 time-varying rate pilots found that, under an opt-in rate structure, less than 20 percent of customers enrolled. In contrast, the two utilities that employed a default (opt-out) design attained enrollments of more than 90 percent of customers. After a year, the default design retained a slightly larger proportion of customers than even the opt-in structure.[69]

Figure 13. TOU enrollment and retention levels



Until customers become more familiar with time-varying rates, opt-in programs will likely be the norm. Where opt-in rates are used, utilities must do more than simply establish the rate—they must actively encourage enrollment through a combination of education, outreach, and incentives. In addition, it is important to ensure that utility incentives, auto dealership incentives, and customer incentives are all aligned.

Activities to maximize EV customer enrollment in EV rates may include:

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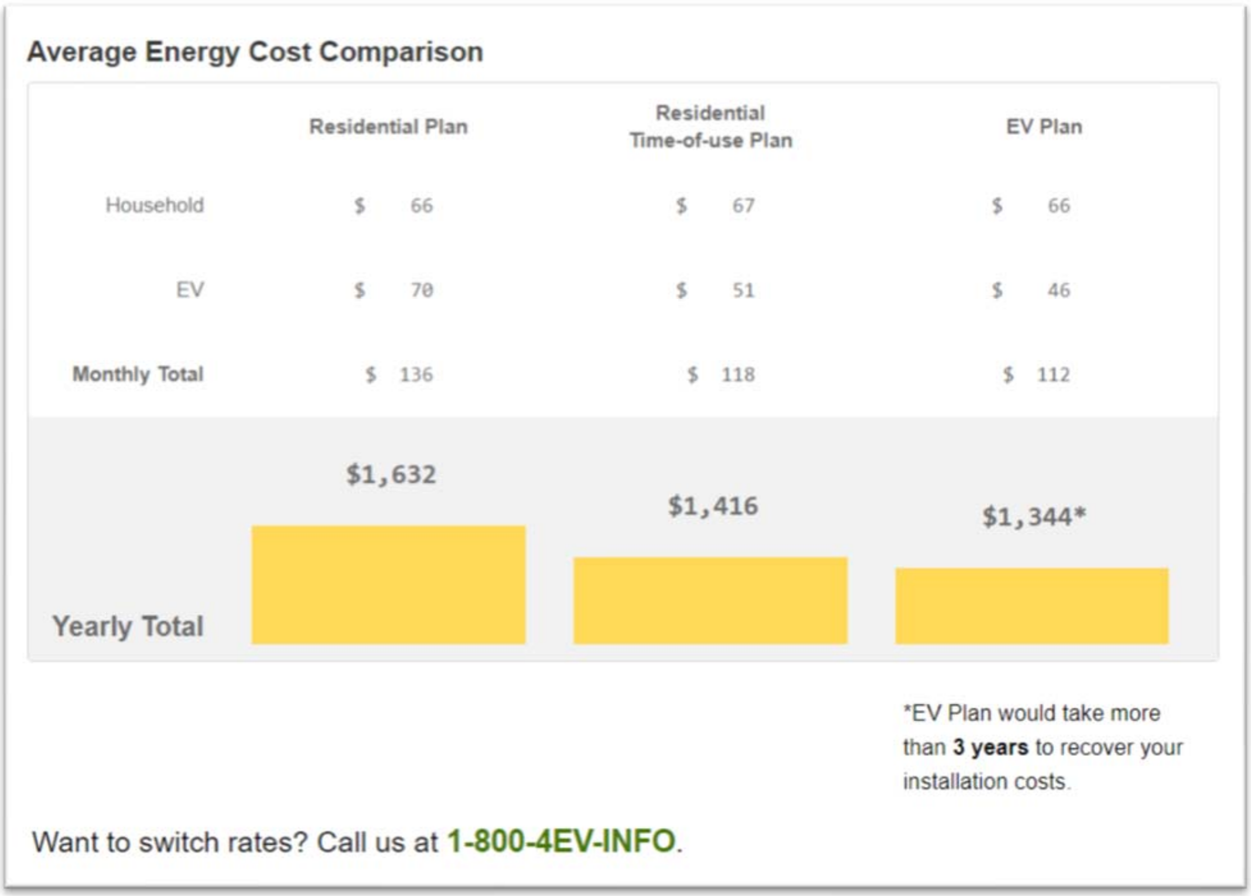
[68] For example, in 2017 SDG&E proposed a residential EV rate that would include both an hourly dynamic rate and critical peak pricing, the timing of which would vary by circuit across the utility's territory. Regulators rejected the rate design, stating "While some early adopting customers may be savvy enough to monitor and respond to daily price signals, SDG&E has provided no evidence suggesting the average residential customer will respond to a different charging period every day based on day-ahead pricing signals." *See: Proposed Decision of ALJs Goldberg and Cooke, Decision on the Transportation Electrification Standard Review Projects, Application 17-01-020 et al., March 30, 2018, page 47.*

[69] Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies; Smart Grid Investment Grant Program; November 2016.

- **Website Tools:** Determining whether an EV rate will save a customer money is a complex quantitative exercise. Rate comparison calculators, such as Southern California Edison's Electric Vehicle Rate Assistant Tool, provide an easy way for customers to compare their cost savings over several different rate options. The image below shows a screenshot of sample results from the Rate Assistant Tool—a simple web-based tool that guides customers through the rate comparison process.[70] We note that the rate assistant tool also provides a dedicated EV customer service phone number that customers can call to enroll.

Figure 14. Example web-based rate comparison calculator



- **Dealership Education and Incentives.** Lack of familiarity with EVs can lead auto sales representatives to shy away from selling EVs, or even to actively discourage purchase of EVs.[71] Furthermore, auto sales representatives often have little to no understanding of the rates available to EV drivers. For example, Consumer Reports found that "When asked how much it would cost to charge an EV, only about 19 percent of salespeople

[70] https://www.sce.com/wps/portal/home/residential/electric-cars/charging-and-installation/EV-Rate-Assistant

[71] John Voelcker, "Many Car Dealers Don't Want To Sell Electric Cars: Here's Why," *Green Car Reports*, February 14, 2014, https://www.greencarreports.com/news/1090281_many-car-dealers-dont-want-to-sell-electric-cars-heres-why.

gave reasonably accurate answers."[72] In California, a dealership training curriculum was developed and is conducted by a collaboration of organizations, and a $250 dealership incentive is provided for each EV purchase in which the customer also signs up for an EV rate.[73]

- **Direct Outreach to EV Customers.** It can be difficult for a utility to identify which of its customers have purchased an EV. To identify customers, it may be possible for utilities to work with state agencies to access Department of Motor Vehicle registration records and directly contact EV drivers. Some utilities also offer gift cards or other rewards to customers. For example, Salt River Project in Arizona provides EV customers with a $50 gift card simply for signing up for the utility's EV mailing list. Establishing these points of contact can be an important first step to educating and enrolling customers in an EV rate.

- **Price Guarantees:** Many utilities offer a price guarantee for the first six months to a year that a customer enrolls in a time-varying rate. These guarantees ensure that the customer will not pay more on the time-varying rate than they would on a standard rate, thereby reducing the customer's risk of signing up for a rate structure that is new to them.

[72] Charles Morris, "Are Auto Dealers the EV's Worst Enemy?," *Charged Electric Vehicles*, September 9, 2014, https://chargedevs.com/features/are-auto-dealers-the-evs-worst-enemy/.

[73] The monetary incentive was recently approved for SDG&E. *See:* California Public Utilities Commission. Decision on the Transportation Electrification Priority Review Projects. Decision 18-01-024. January 11, 2018, page 39.

4. Assessment of New York Utility EV Rate Proposals

Recent utility attention to EV rate design in New York State has arisen partly in response to a state law requiring that each New York electric IOU file an application to establish a residential tariff for the purpose of charging EVs no later than April 1, 2018.[74] This same law allows for periodic updates to residential EV rates, and it requires that IOUs regularly report on the number of customers taking service under the residential EV tariff and the total amount of electricity delivered under the tariff.[75]

In March 2018, all six New York electric IOUs submitted filings in compliance with requirements to develop residential EV tariffs. Three of the utilities—Con Edison, Niagara Mohawk Corporation d/b/a National Grid (National Grid), and Orange and Rockland Utilities, Inc. (O&R)—stated that their compliance was based on previously proposed or implemented EV TOU rates.[76] The other three—Central Hudson Gas & Electric Corporation (Central Hudson), New York State Electric and Gas Corporation (NYSEG), and Rochester Gas and Electric Corporation (RG&E)—proposed new residential EV tariffs for consideration by the New York Public Service Commission.[77]

Below, we assess the tariffs that the New York IOUs propose to use to comply with the requirement that they develop and maintain residential EV rates. We evaluate both design considerations and the likely impact of these tariffs on customer fuel costs.

4.1. Positive Aspects of Residential EV Rate Proposals

Each of the proposed residential EV rates shares certain important and positive characteristics. Chief among these are the inclusion of a TOU rate structure and a price guarantee mechanism.

Overarching Rate Design Structure

Each of the proposed residential EV tariffs incorporates a reasonable rate design structure. Specifically, each proposed rate uses a TOU structure and does not include a demand charge. As discussed previously, TOU rate designs combine efficient price signals with simplicity to provide an accessible price signal for residential customers. TOU energy rates provide a clear incentive for EV customers to charge their vehicles during low-cost, off-peak hours without requiring that these customers pay constant attention to their hour-to-hour energy usage. Customer charges should generally be kept to low levels

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74 New York Public Service Law Section 66-o(2)

75 New York Public Service Law Section 66-o(6)

76 Con Edison Compliance Filing Regarding Compliance with Public Service Law § 66-o. March 30, 2018; National Grid Compliance Filing Regarding Public Service Law Section 66-o(2) – Residential Tariff for Electric Vehicles. March 30, 2018; O&R Compliance Filing Regarding PSL§ 66-o. March 30, 2018. To date, adoption of these existing TOU rates has been minimal. For example, Con Edison recently indicate that fewer than 2,000 customers, or less than 0.1 percent of residential customers, have adopted its residential TOU rate. See Con Edison AMI Metrics Report Appendix 18. April 30, 2018. Filed in New York Public Service Commission Docket 16-00253.

77 Central Hudson Letter to Public Service Commission Regarding Compliance Filing to Effectuate Amendments to Public Service Law § 66. March 29, 2018.; NYSEG & RG&E Compliance Filing Regarding Plug-In Electric Vehicle Tariff. March 30, 2018.

but are a reasonable mechanism for recovering costs that are clearly tied to the number of customers on a utility system, such as costs for installing and reading meters.

It is worth noting that the state law requiring the establishment of residential EV rates does not include any requirements or guidance regarding the design of those rates. It is therefore commendable that the New York IOUs developed TOU rate structures.

Price Guarantee

Each of the New York IOU proposals includes a whole-house TOU rate with a one-year price guarantee. Under this mechanism, customers switching onto the whole-house TOU rate have the option of comparing their first-year charges to the charges they would have incurred if they had remained on their original rate. If they pay more under the TOU rate, the customers will be eligible to receive the difference between what they actually paid and what they would have paid under the standard rate. This feature provides the type of assurance that is helpful for convincing wary customers to switch onto a TOU rate. This insurance against a bad outcome is particularly important in the context of new rate options that a customer must be enticed to adopt (rather than being defaulted onto), as is the case in New York.

4.2. Fuel Cost Savings Under EV Rates

Even with a one-year price guarantee, EV owners are only likely to switch to and remain on TOU rates if those rates provide noticeable savings relative to their standard rates. Without such savings, there is little incentive for customers to transition to a new rate, or to remain on that rate.

Fuel cost savings are also one of the primary motivators of EV purchase decisions.[78] Providing greater fuel cost savings from charging an EV on a TOU rate relative to filling up a gas-powered vehicle incentivizes customers to purchase an EV and contribute to the achievement of New York's EV adoption policy goals.

To determine whether the proposed rates would provide meaningful fuel cost savings, we estimated per-vehicle annual fuel cost savings of charging an EV under the IOUs' proposed TOU rates relative to both charging an EV on a standard rate and operating an ICE vehicle.

Our analysis sought to account for all the various fuel cost components faced by EV owners, including incremental customer charges, TOU delivery charges, standard offer service supply charges, and various miscellaneous volumetric charges.[79] We assumed ICE fuel costs based on average monthly regional gas

[78] Singer, "The Barriers to Acceptance of Plug-in Electric Vehicles: 2017 Update."

[79] These include Merchant Function charges, Clean Energy Standard charges, System Benefit Charges, and Revenue Decoupling adjustments.

prices from 2017.[80] Monthly assumptions for average vehicle miles traveled were derived from research conducted by the AAA Foundation for Traffic Safety.[81]

Our analysis focused on average savings for an owner of a typical full battery electric vehicle (BEV) with a range of 100 miles, similar to a Nissan Leaf or a BMW i3. Based on the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2018, we assume that 100-mile BEVs achieve an average fuel efficiency of 93 miles per gallon of gasoline equivalent, or 2.8 miles per kWh.[82]

We evaluated savings under two charging profiles for customers on EV TOU rates: one in which all charging takes place during off-peak hours, and one consistent with the typical charging patterns of California EV customers facing TOU rates, in which most – but not all – charging occurs during off-peak hours. The latter profile is more likely to be representative of actual customer charging behavior. Consideration of this more realistic charging behavior is important for ensuring that customers will have a reasonable opportunity to achieve fuel savings, even when they must occasionally charge during on-peak hours. This aspect of EV rate design was recognized by the California Public Utilities Commission, who wrote:

> Although our goal is to maximize off-peak charging, we appreciate that, at times, Electric Vehicle owners will need to charge their vehicles during peak periods or may simply find it convenient to do so. To ensure broad consumer acceptance of Electric Vehicles, it is crucial to accommodate the Electric Vehicle owners' charging needs and preferences…[83]

We discuss the results of our analysis in the following sections.

Results: TOU Savings Relative to Charging on Standard Rate

Whole-House TOU Rate

Our analysis indicates fuel cost savings provided by the IOUs' whole-house residential EV rates relative to standard residential rates vary substantially across utilities. Figure 15 presents fuel cost savings by utility and charging pattern.

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[80] New York State Energy Research and Development Authority. Monthly Average Motor Gasoline Prices. https://www.nyserda.ny.gov/Researchers-and-Policymakers/Energy-Prices/Motor-Gasoline/Monthly-Average-Motor-Gasoline-Prices. According to this date, statewide gasoline prices averaged $2.49 per gallon in 2017.

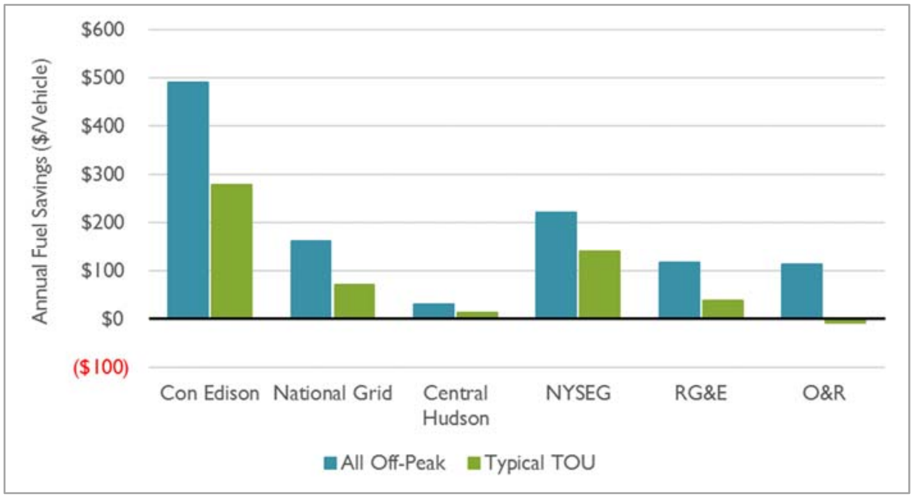
[81] AAA Foundation for Traffic Safety, American Driving Survey 2015-2016. https://aaafoundation.org/wp-content/uploads/2018/02/18-0019_AAAFTS-ADS-Research-Brief.pdf; AAA Foundation for Traffic Safety, American Driving Survey 2013-2014. https://newsroom.aaa.com/wp-content/uploads/2015/04/REPORT_American_Driving_Survey_Methodology_and_year_1_results_May_2013_to_May_2014.pdf. Based on this data, the average vehicle travels 11,381 miles per year.

[82] U.S. EIA. AEO 2018 Table 41. https://www.eia.gov/outlooks/aeo/supplement/excel/suptab_41.xlsx .We note that this assumption is likely conservative, as many new EVs have fuel economies of 3.3 miles per kWh.

[83] California Public Utilities Commission, D.11-07-029 Establishing Policies to Overcome Barriers to Electric Vehicle Deployment and Complying with Public Utilities Code Section 740.2, July 14, 2011, 15.

Assuming that all charging occurs off-peak, customers of all utilities would benefit from fuel cost savings, but the magnitude of these savings varies greatly across utilities. The rates proposed by Con Edison and NYSEG offer the greatest potential savings, with Con Edison customers experiencing annual fuel cost savings of approximately $500. Customers of RG&E, National Grid, and O&R experience savings of about $100 per year. In Central Hudson's territory, where there is a relatively small difference between on-peak and off-peak TOU rates, average annual savings amount to less than $50 even if all charging takes place during off-peak hours.

Figure 15. Whole-house TOU rate annual fuel cost savings relative to standard rate



Source: Synapse Energy Economics analysis.

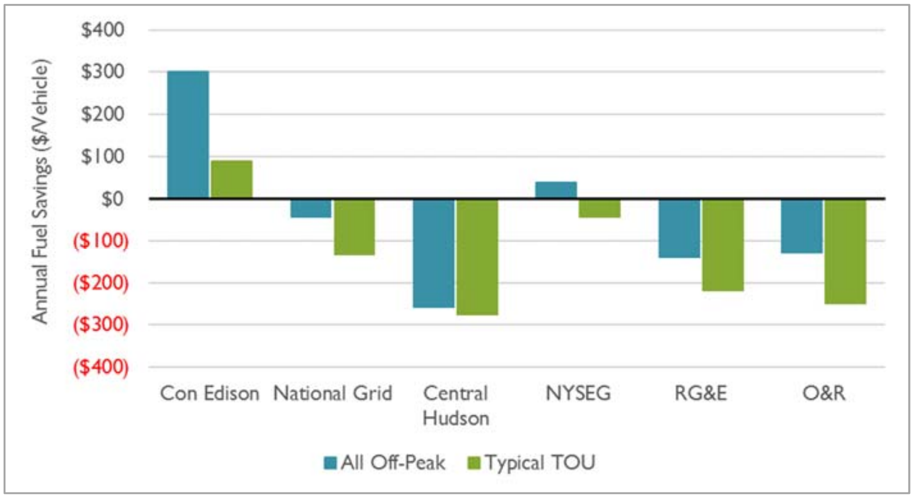
Under the scenario in which most, but not all, charging occurs during the off-peak period, the fuel cost savings are reduced substantially. A typical 100-mile BEV customer would be expected to save an average of approximately $250 per year at Con Edison. In contrast, we would expect that a typical O&R customer would experience a small *increase* in fuel costs from switching onto the proposed residential EV rate. Meanwhile, an average EV customer of Central Hudson or RG&E would experience fuel cost savings of less than $50 per year from switching rates. The benefits of such low savings in the Central Hudson and RG&E territories may not outweigh the inconvenience and risk associated with whole-house TOU rates.

EV-Only TOU Rate

Several of the New York IOU residential EV tariff proposals—including those of Con Edison, O&R, NYSEG, and RG&E—include the option for customers to charge EVs under a separately metered TOU rate, rather than under the whole-house TOU rate. However, separately metered customers would likely have to pay a full extra customer charge on top of their standard service customer charge. In exchange, these customers would not have to worry about managing their regular household appliance load in accordance with TOU periods.

Figure 16 shows that customers receive fewer fuel cost savings from switching to a separately metered TOU rate, as their higher total customer charge offsets the savings associated with a lower off-peak energy charge.[84] In fact, we estimate that typical separately metered EV customers would incur increased fuel costs in the service territories of every utility other than Con Edison. Customers of O&R could incur additional EV fuel costs of $250 by switching to the separate-meter TOU rate.

Figure 16. EV-only TOU rate annual fuel cost savings relative to standard rate



Source: Synapse Energy Economics analysis.

Results: EV Fuel Cost Savings Relative to ICEs

We find that the fuel cost savings provided by EVs on the proposed TOU rates relative to ICEs also vary greatly depending on the utility and the ICE in question. Figure 17 presents our calculated fuel cost savings for each utility for a typical 100-mile BEV on a whole-house TOU rate relative to two alternative types of ICEs: a typical new car with an efficiency of 38 mpg, and a standard hybrid with an efficiency of 55 mpg.[85]

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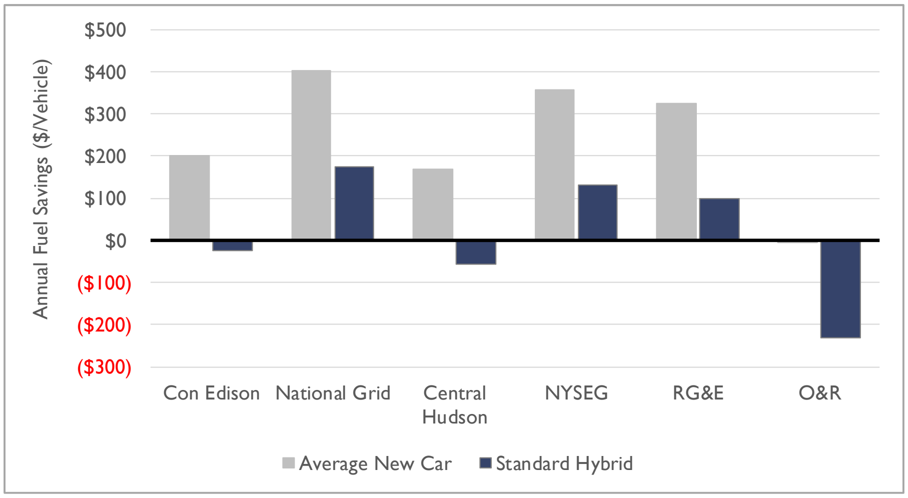
[84] Although National Grid and Central Hudson did not specifically propose to allow EV customers to separately meter their EV loads, for the purposes of a comparative analysis we assumed that this would be allowed. The changes in fuel cost savings from Figure 15 to Figure 16 for National Grid and Central Hudson are due to the additional customer charge that we assume these customers would be required to pay in order for the EV to be metered separately.

[85] U.S. EIA. AEO 2018 Table 41. https://www.eia.gov/outlooks/aeo/supplement/excel/suptab_41.xlsx . Standard hybrids do not draw electricity from an external source, and therefore must rely at least in part on gasoline during their standard operation. A Toyota Prius is one of the more common examples of a standard hybrid vehicle.

Figure 17. Annual fuel cost savings of 100-mile BEV on whole-house TOU rate relative to alternative ICE types



Source: Synapse Energy Economics analysis.

In nearly all utility service territories, an EV operating under the utility-proposed whole-house TOU rate would generate positive fuel cost savings relative to a typical new gasoline-powered vehicle. The savings provided by a new EV relative to a typical new ICE range up to more than $400 per year for a National Grid customer, although they are essentially zero for O&R customers.

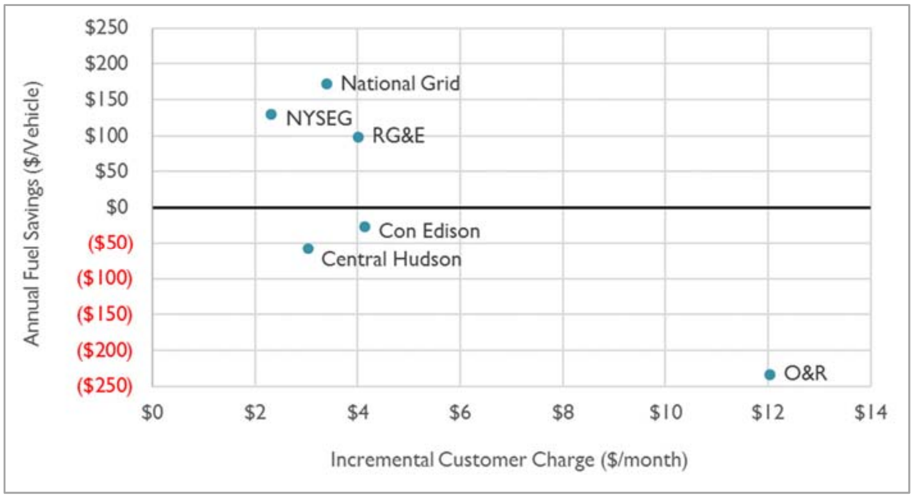
When compared to a standard hybrid vehicle, such as a Toyota Prius, EV fuel savings largely disappear. At three of the six IOUs, an EV customer would likely have higher fuel costs relative to a hybrid vehicle. This comparison is important, because customers considering purchasing an EV are likely to compare these vehicles to high-efficient ICE options, such as standard hybrids.

Once again, our analysis indicates that the EV TOU rates proposed by O&R and Central Hudson are the least favorable to EV customers. We estimate that a typical EV customer would incur increased annual fuel costs of more than $200 relative to a standard hybrid in O&R's territory, and more than $50 in Central Hudson's territory. In contrast, EV TOU customers of National Grid and NYSEG would experience annual fuel cost savings of more than $130, even compared to a standard hybrid. We note that for cost-conscious vehicle purchasers, an EV's fuel cost savings would need to be sufficiently large to out-weigh the current higher up-front costs of an EV.

Role of Customer Charges

One of the main determinants of the variation in our fuel cost savings estimates across utilities appears to be the level of incremental customer charge incorporated in each whole-house TOU rate. All six utilities charge customers at least an additional two dollars per month in fixed customer charges when they switch from a standard rate to a whole-house TOU rate. For five of those utilities, the incremental customer charge is less than $4.50 per month. But for O&R, it is $12.00 per month, nearly three times greater than any other utility. This goes a long way toward explaining why our results indicate that O&R's EV TOU rate option offers the lowest fuel cost savings relative to both a standard residential rate and an ICE. Figure 18 provides evidence of a negative, if imperfect, relationship between the incremental customer charge and fuel cost savings of an EV on a utility's TOU rate relative to a standard hybrid vehicle.

Figure 18. Average annual fuel cost savings of 100-mile BEV relative to standard hybrid compared to customer charge increase



Source: Synapse Energy Economics analysis.

It is unclear to what extent higher customer charges faced by whole-house TOU customers are justified. Customer charges typically recover a variety of costs associated with serving a customer, such as billing and customer service costs, as well as the cost of the meter, final line transformer, and service drop. Some of these costs may be higher for a whole-house TOU customer than for a customer on standard rate, particularly if a more sophisticated meter is required for measuring hourly usage. However, most costs (such as the cost of the final line transformer and service drop) will not be higher. It is very unlikely that the large incremental customer charge incurred by O&R customers is justifiable on cost causation grounds, much less on grounds of encouraging adoption of TOU rates or purchase of EVs.

4.3. Additional Important EV Rate Design Characteristics

Besides overall rate design structure and impacts on fuel costs, there are several other design characteristics that can impact the effectiveness and efficiency of EV rates. We again find major differences among the New York IOU proposals across several of these characteristics. Below, we focus on the proposals' peak-to-off-peak price ratios, relationship to standard offer service rates, and alignment of TOU periods with system costs.

Ratio Between Peak and Off-Peak Rates

The ratio between peak and off-peak prices is a key determinant of the effectiveness of TOU rates at encouraging EV customers to charge during off-peak hours. A study of early-adoption EV customers in

SDG&E service territory found that a peak to off-peak price ratio of 6:1 results in about 10 percent more off-peak charging than a ratio of 2:1.[86]

Table 2 lists the ratios between peak and off-peak TOU delivery charges under the whole-house TOU rates proposed for residential EV customers by each of the IOUs. Con Edison and O&R each offer rates with ratios greater than 14:1 in the summer months, and greater than 5:1 in the winter months. In contrast, Central Hudson's rate has a ratio of only 1.2:1 throughout the year. Such a low ratio has two likely repercussions. First, it makes it less likely that customers who adopt the TOU rate will charge their EVs exclusively during off-peak periods. Second, it lessens the opportunity for EV customers to control and reduce their fuel expenses. This effect helps explain why our analysis finds that Central Hudson's proposal would result in such low (and sometimes negative) fuel cost savings for EV customers.

Table 2. Ratios between peak and off-peak TOU delivery charge

Utility	Summer	Winter
Con Edison	14.2	5.2
National Grid	6.5	6.5
Central Hudson	1.2	1.2
NYSEG	2.7	2.7
RG&E	2.7	2.7
O&R	15.5	5.6

Relationship to Standard Offer Service Rates

Another important distinction among the EV TOU rate offerings of the New York utilities is the extent to which those rates are linked with TOU energy supply rates. Since New York is a competitive retail access state, the IOUs do not provide energy supply services to all residential customers. However, they do provide standard offer service rates to customers who do not select a competitive supplier. These utilities therefore have the ability to offer TOU standard offer service rates to complement the delivery TOU rates that they are presenting as their residential EV tariffs.

It appears that all six IOUs already offer TOU standard offer service rates to complement their TOU delivery rate offerings. However, there is variation in the degree to which these standard offer service offerings contribute to strong differentials between the total energy charges faced by TOU customers during on-peak and off-peak periods. Con Edison offers rates that vary dramatically between peak

[86] Nexant. 2014. "Final Evaluation of SDG&E Plug-in Electric Vehicle TOU Pricing and Technology Study." Available at www.sdge.com/sites/default/files/documents/1681437983/SDGE%20EV%20%20Pricing%20&%20Tech%20Study.pdf.

summer hours and other times of the year, whereas the TOU standard offer service offerings of NYSEG and RG&E do not exhibit marked differences between peak and off-peak hours.

Given that customers ultimately perceive and pay a total per-kWh energy charge that incorporates both delivery and supply charges, it is important that both delivery and standard offer service TOU offerings contribute to an efficient price signal regarding the least-cost times to charge EVs. The difference in price ratios across the utilities for standard offer service prices may be due to variations in zonal wholesale market prices. However, it is worth reviewing the price differentials to ensure that the standard offer service prices are as efficient as possible.

TOU Periods

Another point of inconsistency across the New York IOUs is in their selection of on-peak and off-peak hours. All of the utilities apply their highest peak TOU rates to summer (June through September) weekdays between 2 p.m. and 7 p.m. Beyond that point of consistency, differences arise.

One notable inconsistency is in the seasonality of peak periods. O&R and Con Edison offer peak periods that are limited to just the summer months. These utilities apply a “semi-peak” rate in between the on-peak and off-peak rates to winter afternoon and evening hours. All other utilities apply the same price to all hours throughout the year.

The summer focus of O&R and Con Edison is likely rooted in the fact that New York has a summer-peaking electricity system. In each of the past three years, each of the top 100 annual peak system hours occurred between June and September.[87] However, the timing of peak periods should account for marginal energy costs as well as marginal system capacity costs. Though New York’s peak load events occur during the summer, its highest energy prices often occur during winter evenings. Figure 19 presents a heat map showing that the highest system energy prices in 2017 came during the months of December and January between 4 p.m. and 9 p.m.[88] Accounting for this pattern, it likely makes sense to apply peak periods to winter evenings, as most New York IOUs do.

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[87] NYISO Market & Operational Data, Custom Reports: Real-Time Actual Load. http://www.nyiso.com/public/markets_operations/market_data/custom_report/index.jsp?report=rt_actual_load

[88] NYISO Market & Operational Data, Custom Reports: Day-Ahead Market LBMP – Zonal. http://www.nyiso.com/public/markets_operations/market_data/custom_report/index.jsp

Figure 19. 2017 average NYISO locational marginal prices

	Month											
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
1	$29	$24	$24	$18	$18	$18	$22	$20	$17	$17	$19	$32
2	$27	$22	$23	$17	$16	$16	$20	$18	$15	$15	$17	$30
3	$26	$21	$22	$16	$15	$15	$18	$16	$13	$14	$16	$28
4	$25	$21	$22	$16	$14	$14	$17	$15	$12	$13	$16	$28
5	$26	$21	$22	$16	$14	$13	$16	$15	$12	$13	$16	$29
6	$28	$23	$24	$17	$16	$14	$16	$16	$14	$15	$19	$33
7	$33	$27	$31	$23	$21	$17	$18	$17	$17	$22	$26	$42
8	$36	$29	$35	$26	$24	$20	$21	$19	$18	$24	$30	$45
9	$38	$29	$35	$30	$26	$22	$24	$22	$20	$23	$31	$46
10	$39	$30	$34	$31	$28	$25	$26	$24	$22	$25	$31	$47
11	$38	$29	$33	$30	$29	$26	$28	$26	$23	$25	$30	$47
12	$37	$29	$32	$30	$28	$28	$31	$28	$25	$26	$29	$44
13	$35	$27	$30	$28	$27	$30	$33	$29	$26	$25	$27	$41
14	$34	$26	$28	$27	$27	$31	$36	$31	$28	$25	$27	$39
15	$33	$26	$27	$26	$27	$32	$38	$33	$30	$26	$26	$39
16	$33	$26	$26	$25	$27	$34	$40	$35	$32	$26	$27	$40
17	$39	$28	$28	$26	$28	$35	$43	$36	$34	$28	$32	$51
18	$50	$36	$31	$28	$31	$36	$43	$36	$33	$30	$39	$66
19	$48	$39	$36	$30	$29	$32	$37	$31	$30	$34	$38	$62
20	$43	$35	$40	$34	$30	$30	$34	$29	$31	$34	$35	$56
21	$39	$31	$37	$36	$33	$29	$32	$28	$28	$28	$31	$50
22	$36	$28	$32	$28	$27	$27	$29	$26	$23	$24	$27	$44
23	$32	$26	$27	$22	$22	$22	$25	$22	$19	$20	$23	$38
24	$29	$24	$24	$19	$20	$19	$23	$20	$18	$18	$19	$34

The choice of peak hours within a season is another area of difference across the IOUs. Central Hudson's peak period is the narrowest of the utilities, running from 2 p.m. to 7 p.m. O&R's peak period is limited to summer hours between noon and 7 p.m. The peak periods of the other four IOUs are much longer, lasting from at least 8 a.m. through 11 p.m. Based on load and price data from the past three years, the longer peak periods appear to better capture higher-cost hours without stretching into the lowest-cost overnight hours.[89] Figure 19 indicates that Central Hudson's shorter peak period would miss both the winter morning peak and the end of the winter evening peak, which represent some of the highest-cost hours of the year. In addition, over the past three years the top 100 annual NYISO peak hours have included summer hours between 10 a.m. and 2 p.m., and between 7 p.m. and 9 p.m.

4.4. Metering

None of the New York IOUs have proposed a submetering option using an EVSE for their EV rates, nor have they explained why EVSE submetering was not proposed. Instead, all of the IOUs would require

[89] Of course, peak periods should not be so long as to produce brief off-peak periods that may limit fuel cost savings opportunities and lead to distribution peak clustering concerns. However, as long as the off-peak period remains at least eight hours in length, these concerns are likely to be minor.

traditional utility meters for customers who wish to enroll in an EV-only rate, with the exception of Con Edison's ongoing SmartCharge NY program (which uses the FleetCarma C2 device). The failure of the New York utilities to consider submetering options could dampen enrollment levels in the proposed EV TOU rates.

4.5. Reporting Metrics

Regardless of the rate designs ultimately implemented for EV customers, it will be important to use the lessons learned to improve rate design moving forward. To enable data-driven assessment of the effectiveness of each utility's rates, we propose that the utilities report additional data to the Commission and stakeholders. Ideally, such reporting would occur frequently enough to make mid-course corrections, if necessary. We recommend that the utilities file publicly available quarterly reports containing the following metrics and data (in spreadsheet format):

- Number of customers on whole-home versus EV-only rate
- Number of customers who opted to leave the TOU rate
- Aggregated customer load profiles, including the percentage of EV charging that occurred on-peak versus off-peak
- Monthly average energy (kWh) and peak demand (kW) associated with EVs
- Costs to integrate EVs into the grid, including the location of any distribution upgrades and the type of upgrade required
- TOU rate education and outreach activities undertaken by utilities, including relevant budgets
- Lessons learned and modifications made; for example, if low enrollments prompted a utility to seek an alternate marketing approach, this should be discussed.

4.6. Enrollment in TOU Rates

While the design of TOU rates is critical to ensuring their success, even the best-designed rates will suffer from low enrollment levels if customers are not well informed regarding the rate options and potential fuel savings, or if enrollment is time-consuming and difficult. Each of the New York IOUs currently has a residential TOU rate in place.[90] Enrollment in these rates has been exceedingly low: Only one IOU has seen more than 1 percent of its residential customers choosing the TOU rate, as shown in Table 3, below.

[90] Note, however, that there is no on-peak to off-peak distribution rate differential for NYSEG and RG&E.

Table 3. Residential enrollment in TOU rates currently in effect

Utility	Residential TOU Customers	Total Residential Customers	% TOU
National Grid	5,624	1,475,271	0.4%
Con Edison	1,720	2,896,029	0.1%
Central Hudson	1,000	266,061	0.4%
RG&E	1,273	334,750	0.4%
NYSEG	4,016	766,954	0.5%
O&R	3,399	198,331	1.7%

Sources: Con Edison AMI Metrics Report Appendix 18. April 30, 2018. Filed in NY PSC Docket 16-00253; Niagara Mohawk Rate Case Testimony of Electric Rate Design Panel. April 28, 2017. Book 20, Exhibit 1 (p. 77). NY PSC Case No. 17-E-0238; Central Hudson Cost of Service Exhibits. July 28, 2017. (p. 6). NY PSC Case No. 17-E-0459; RG&E Revenue Allocation, Rate Design, Economic Development, and Tariff Panel Testimony. May 20, 2015. (p. 73). NY PSC Case No. 15-E-0285; NYSEG Revenue Allocation, Rate Design, Economic Development, and Tariff Panel Testimony. May 20, 2015. (p. 61). NY PSC Case No. 15-E-0283; O&R Electric Rate Filing Exhibits. January 26, 2018. Volume 2 (p. 522). NY PSC Case No. 18-E-0067.

To encourage EV customers to enroll in a TOU rate, the IOUs must do more than simply establish the rate. They must actively encourage enrollment through a combination of education, outreach, and incentives. In addition, utility incentives, auto dealership incentives, and customer incentives should all be aligned. As described in Section 3.5, these activities may include setting up a web-based rate comparison tool and monetary incentives for enrollment in an EV rate (paid either to EV drivers or dealerships who help the customers enroll). In New York, utility incentives could be established through Earnings Adjustment Mechanisms that establish targets not only for customer adoption of EVs, but also for enrollment in an EV rate.

5. Conclusions and Recommendations

Utilities have a unique opportunity to influence EV adoption and steer EV charging practices to benefit the grid and society. To attain these benefits, EV rates must be designed carefully and thoughtfully. Our evaluation of the New York utilities' recent proposals can be used to illustrate many of the rate design principles discussed throughout this report.

The New York utilities have taken an important step in the right direction by offering a whole-house TOU rate that would enable EV drivers to save money on fuel costs, while encouraging beneficial charging behavior. Several of the utilities have also opted to offer an EV-only rate, which provides a great option for customers who are hesitant to adopt a whole-house TOU rate. Further, all of the utilities offer a price guarantee, which reduces the risk to customers of signing up for a new rate.

However, most of the utilities' rate proposals require additional work to unlock their full potential. In many cases, the potential fuel cost savings are minimal, or even negative, relative to the standard rate. Further, the fuel cost savings relative to the cost of operating an efficient ICE (e.g., a hybrid) are generally also low or negative.

To achieve greenhouse gas emission reductions of 40 percent by 2030 and 80 percent by 2050, and to comply with Zero Emission Vehicle (ZEV) regulations that will require approximately 800,000 EVs in New York by 2025, the utilities' EV rate designs must be improved. We offer six recommendations that could commence today:

1) Utilities with low price differentials between on-peak and off-peak rates increase the price ratio to motivate off-peak charging and enable greater fuel savings;
2) Ensure that a customer who charges mostly off-peak achieves fuel savings relative to a customer who remains on a standard rate and charges only on-peak;
3) Reduce or eliminate the customer charge for second meters;
4) Explore submetering as a means to lower the cost for EV-only rates;
5) Evaluate whether the proposed rate will provide sufficient fuel savings to encourage customers to adopt EVs over high-efficiency ICE vehicles; and
6) Endeavor to maximize customer enrollment through education, outreach, and incentives.

Finally, we recommend that these actions on residential rate design be complemented by an analysis of commercial and industrial rates to determine whether modifications are warranted to support EV charging stations, fleet electrification, and workplace charging.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1214

In the Matter of:	**)**
Application of Duke Energy Carolinas,	**)**
LLC for Adjustment of Rates and	**)**
Charges Applicable to Electric Service	**)**
in North Carolina	**)**

DIRECT TESTIMONY OF
JUSTIN R. BARNES
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT JRB-3

The State of Electric Vehicle Home Charging Rates

A SUMMARY

PRESENTED TO
Colorado PUC

PREPARED BY
Ahmad Faruqui
Ryan Hledik
John Higham

October 15, 2018

THE Brattle GROUP

Introduction and Methodology

Introduction

- The purpose of this presentation is to summarize residential EV-specific rate offerings in the United States
- The presentation includes the following sections:
  - Drivers and goals of EV-specific rates
  - A survey of current EV-specific rate offerings
  - Review of two pilot studies of EV-TOU effectiveness

Methodology

- The survey draws upon the following sources:
  - OpenEI Utility Rates Database
  - Utility tariff sheets

Drivers and Goals of EV-Specific Rates

Background

EV rate offerings are an opportunity improve the economic efficiency of EV charging behavior

- Consumer electric vehicles use approximately 225-275 kWh per month
- Level 1 charging consumes 1.4 kW of power
- Level 2 charging uses 6.2-7.6 kW of power
- A majority of EV charging occurs at home

Possible Utility Goals

1. Encourage EV adoption by reducing charging costs
2. Provide price signals that encourage optimal EV charging patterns while accurately collecting costs

I/A

The impact of rate design on EV attractiveness depends on (desired/actual) charging patterns

Annual EV Charging Cost per Traveler

Charging Profiles \ Rate Designs	Flat rate	TOU (3:1 ratio)	TOU (10:1 ratio)	Inclining block rate	Unconstrained demand charge	Peak period demand charge
Off Peak L1	$744	$510	$289	$971	$562	$550
On Peak L1	$744	$1,059	$1,356	$971	$639	$676
Post-Commute L2	$744	$886	$1,021	$971	$976	$1,155
Off Peak L2	$744	$510	$289	$971	$882	$550
On Peak L3	$744	$1,290	$1,807	$971	$1,335	$1,656
Autonomous Fleet	$744	$824	$899	$971	$808	$904

Comparable annual fuel cost of an ICE vehicle at $3/gal, 30 mpg is **$1,460**

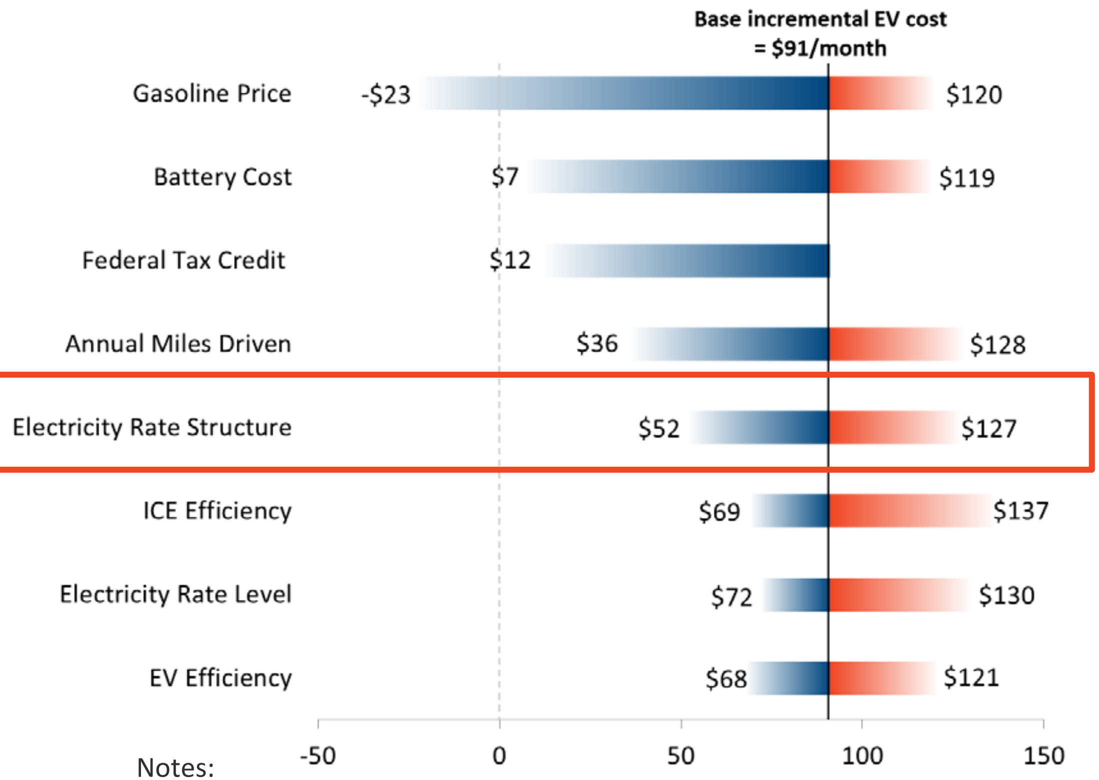
Notes:
Rates and charging profiles are purely illustrative
Typical annual residential electricity bill is $1,140
Assumes constant vehicle miles traveled across all charging profiles
Each rate is applicable to whole home load, but figures shown are only incremental EV charging costs
Rates are revenue neutral for a class average residential customer

- TOU and demand charges incentivize off-peak charging but also introduce an element of financial risk for the EV owner
- It will be important to understand the extent to which customers are able and willing to respond to these price signals
- Technology that automates charging control will likely play a key role
- Fleets with higher utilization likely favor frequent, fast charging and potentially have less flexibility to respond to price signals

I/A

Rate design appears more likely to influence charging patterns than to impact EV adoption

Incremental Monthly Cost of EV Ownership Relative to ICE Vehicle (Illustrative)



Notes:
Results are illustrative.
The "Base incremental EV costs" is a levelized value over the life of the vehicle (10 years, 150,000 miles) reflecting the higher costs of the battery and lower fuel costs. Range shown is based on "high" and "low" assumptions for each key cost driver. See appendix for assumptions behind sensitivity analysis.

Comments

- Rate design appears to impact total EV ownership costs modestly relative to other cost drivers, though this is heavily dependent on charging patterns
- Additionally, there are significant non-economic drivers of vehicle adoption
- Thus, rate design may be a better tool for influencing the behavior of EV owners rather than being a primary consideration in the vehicle purchase decision

Utilities and Types of Rates

21 US utilities are currently offering EV-specific rates

- 12 Investor Owned Utilities
- 6 Municipal Utilities
- 3 Cooperatives

31 unique EV rate designs

- 27 TOU rates (1 of which has inclining blocks)
- 2 Inclining Block rates
- 1 Flat rate
- 1 Flat rate with flat demand charge

Differences in rate applicability

- 18 rates apply to entire residence
- 8 rates apply strictly to EV charging, metered separately (the costs of separate metering are generally incurred by the customer)
- 5 rates can be applied to entire residence or strictly EV charging

Rates – General Trends

- Diverse array of rate offerings
- Most utilities' EV-specific rates are more advantageous than comparable non-EV offerings. Designed to encourage enrollment and off-peak charging by offering:
  - Cheaper off-peak rates
  - Reduced or eliminated tiers of inclining block rate
- A few rates are less advantageous than comparable non-EV rates (longer or more expensive peak periods). These rates are generally required in order to receive utility-sponsored EV rebates or utility-financed charging infrastructure.
- Several pilot programs are testing ultra-high price ratios (>10)
- Several rates are either identical to other non-EV residential rates or are the only TOU rates offered.

TOU Rates

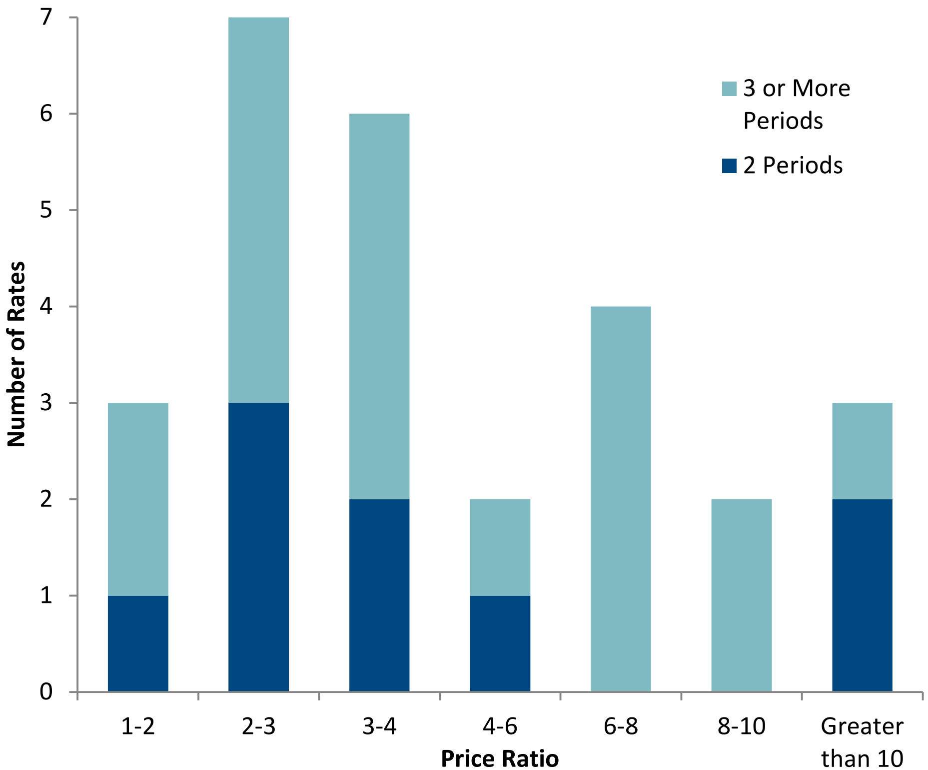
Of the 27 TOU rates:

- 9 have 2 pricing periods in both Summer and Winter
- 11 have 3 pricing periods in both Summer and Winter
- 5 have 3 pricing periods in Summer but 2 in Winter
- 2 have 4 pricing periods

Many different arrangements of pricing periods, seasons, price ratios, and fixed costs.

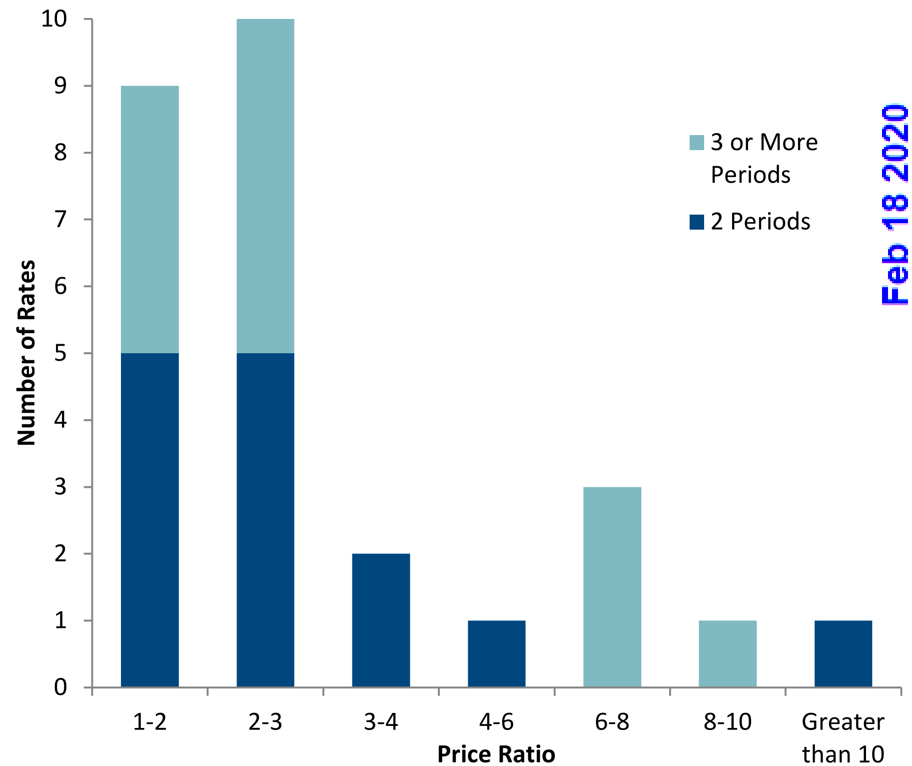
TOU Rates – Price Ratios

Summer Price Ratios (Peak Rate to Lowest Off-Peak Rate)



2 Period Median = 3.19
3 or More Period Median = 3.74

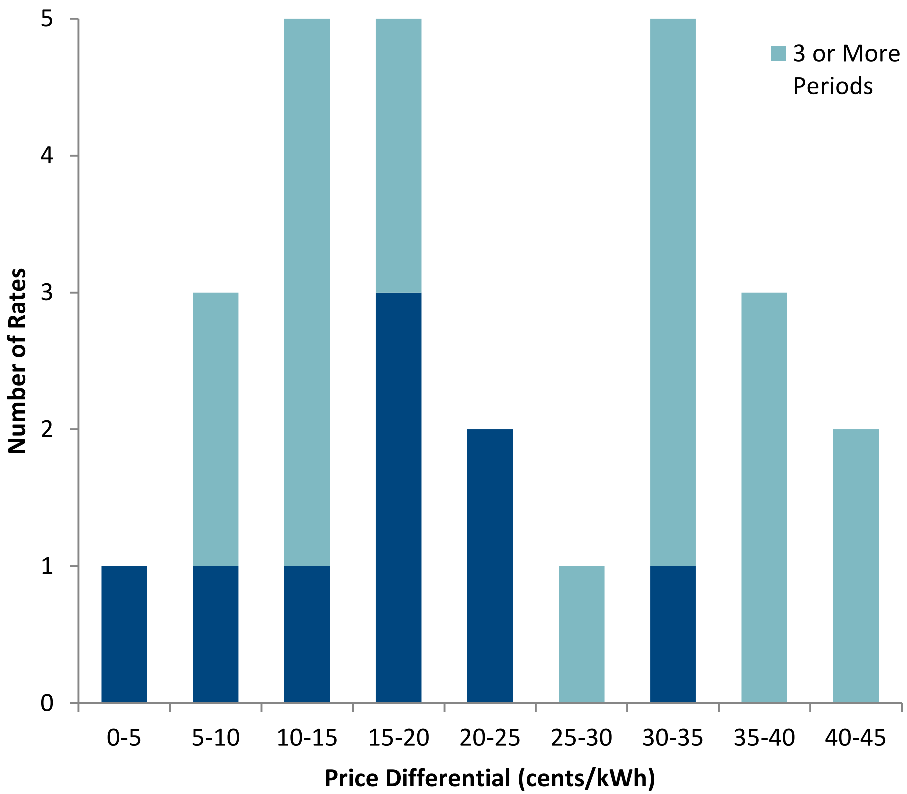
Winter Price Ratios (Peak Rate to Lowest Off-Peak Rate)



2 Period Median = 2.36
3 or More Period Median = 2.54

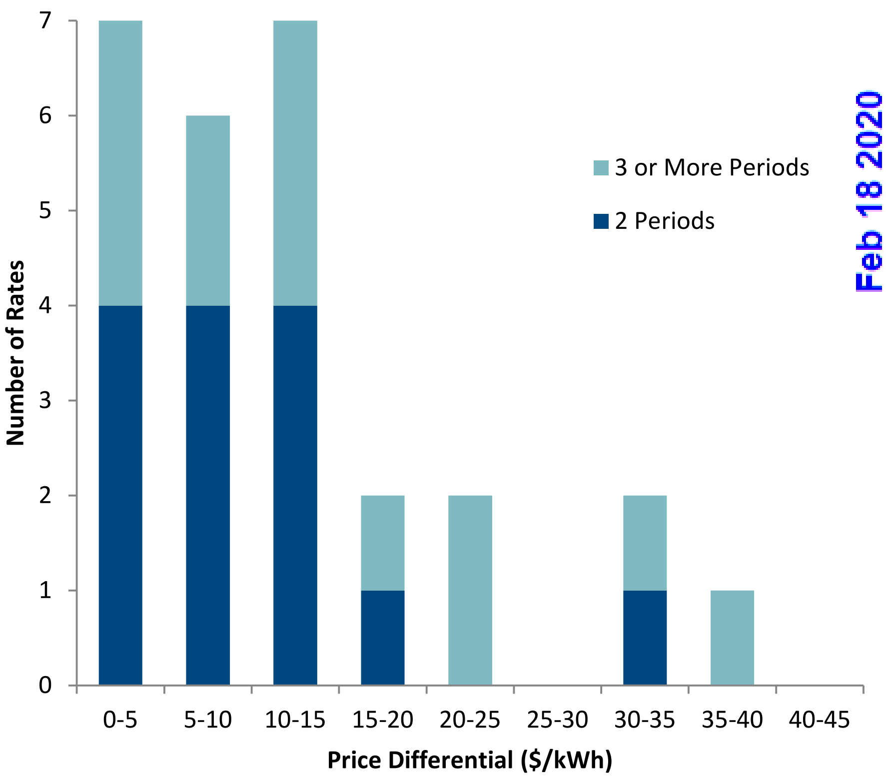
TOU Rates – Price Differentials

Summer Price Differentials (Peak Rate to Lowest Off-Peak Rate)



2 Period Median = 17 cents/kWh
3 or More Period Median = 28 cents/kWh

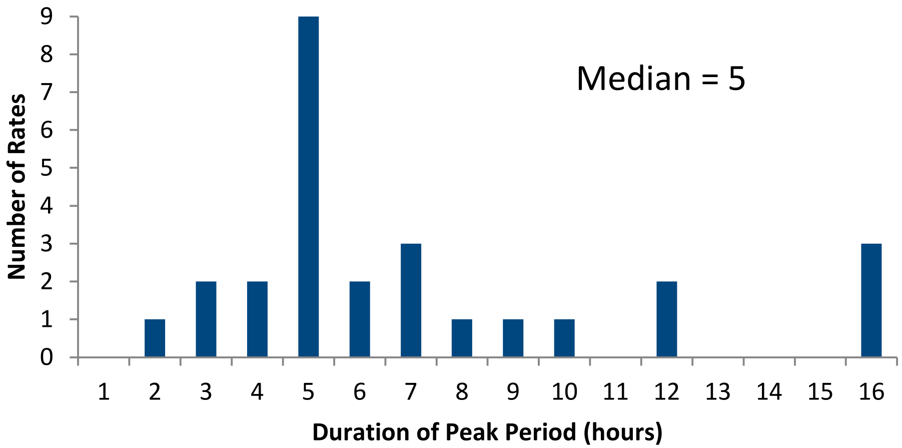
Winter Price Differentials (Peak Rate to Lowest Off-Peak Rate)



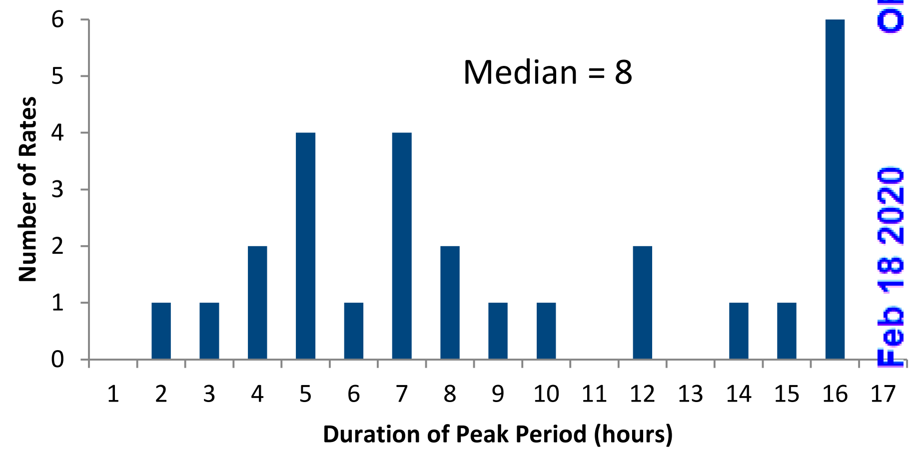
2 Period Median = 9 cents/kWh
3 or More Period Median = 12 cents/kWh

TOU Rates – Duration of Peak Window

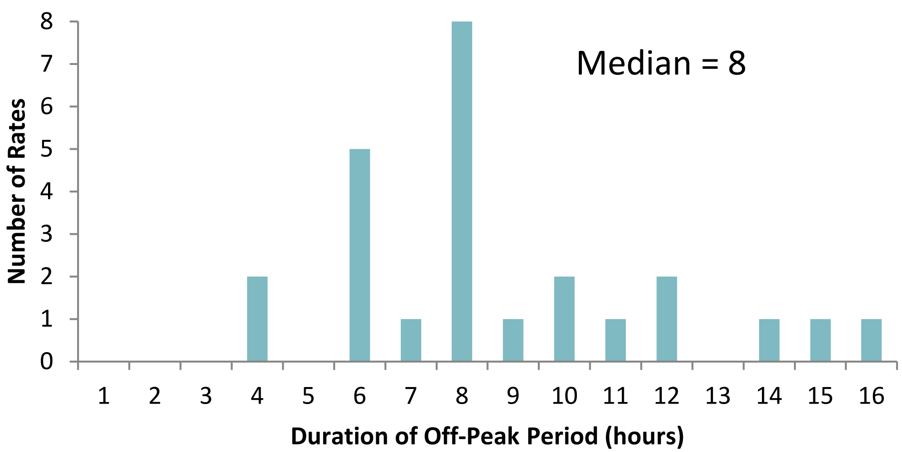
Summer Peak Period Duration



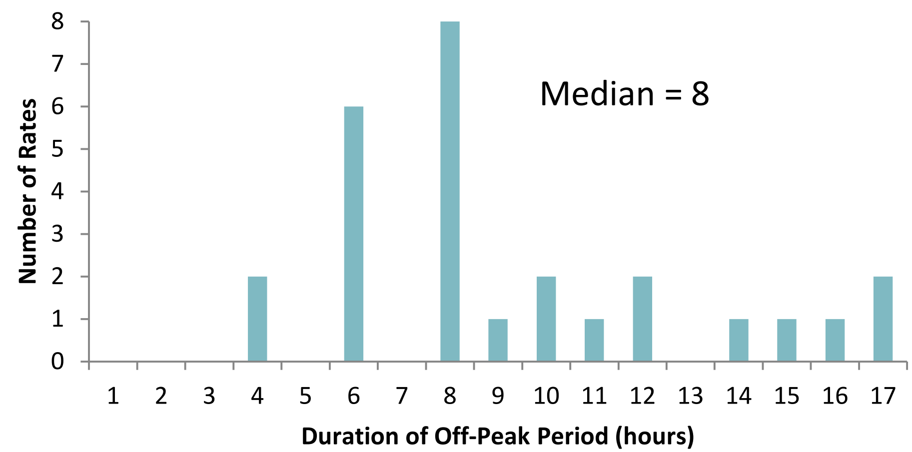
Winter Peak Period Duration



Summer Off-Peak Period Duration



Winter Off-Peak Period Duration



Pilot Studies

San Diego Gas & Electric – EV TOU Pilot Study

- 3 different 3-period rates with varying price ratios (roughly 2, 4, and 6 for peak/super off-peak)
- All rates applied strictly to EV charging, not the entire residence
- 430 participants owning a Nissan LEAF with a charging timer and Level 2 charging
- EV owners were found to be responsive to price signals and shifted a majority of charging to super off-peak hours
- Participants exhibited learning behavior, increasingly shifting consumption as the study progressed

EPRI – Salt River Project EV Driving, Charging and Load Shape Study

- Observational study of 70 EVs of various models subject to different rate plans
- TOU rates found to be highly effective in shifting peak loads
- Energy use and charging load varied widely across different models and charger types

Conclusions

- Electric vehicle owners have significantly different needs, load shapes, and flexibility than other residential customers, supporting the creation of new rate offerings
- EV TOU rates encourage optimal charging patterns, creating a win-win for utilities and EV owners
- Initial findings from two EV charging pilots indicates that charging load is highly responsive to rate design, though further empirical research is needed in this area

References

- Electric Power Research Institute. "Electric Vehicle Driving, Charging, and Load Shape Analysis: A Deep Dive Into Where, When, and How Much Salt River Project (SRP) Electric Vehicle Customers Charge." 3002013754. July 2018.
- Cook, Jonathan, Candice Churchwell, and Stephen George. "Final Evaluation for San Diego Gas & Electric's Plug-in Electric Vehicle TOU – Pricing and Technology Study." Nexant, Inc. Submitted to San Diego Gas & Electric. February 20, 2014.

Appendix: Monthly Cost of EV Ownership Assumptions

General Assumptions:

- 10 year vehicle life
- 24 kWh battery
- 10% registration fee
- 12% charging losses
- $600 charger cost
- 7% annual discount rate

Sensitivity Assumptions:

Component	Units	Low	Base	High
Electricity Rate Level	*cents/kWh*	8	**12**	20
Electricity Rate Structure		Off-Peak w/ TOU (10:1)	**Flat**	Post-Commute w/ Demand Charge
EV Efficiency	*miles/kWh*	5.0	**3.0**	2.0
ICE Efficiency	*MPG*	25	**30**	50
Annual Miles Driven	*miles/year*	30,000	**15,000**	5,000
Federal Tax Credit	*$*	7,500	**0**	---
Battery Cost	*$/kWh*	200	**500**	600
Gasoline Price	*$/gal*	$5.00	**$3.00**	$2.00

PRESENTED BY

Ahmad Faruqui

Principal - San Francisco, CA
+1.415.217.1026
Ahmad.Faruqui@brattle.com

Ahmad Faruqui's consulting practice is focused on the efficient use of energy. His areas of expertise include rate design, demand response, energy efficiency, distributed energy resources, advanced metering infrastructure, plug-in electric vehicles, energy storage, inter-fuel substitution, combined heat and power, microgrids, and demand forecasting. He has worked for nearly 150 clients on 5 continents. These include electric and gas utilities, state and federal commissions, independent system operators, government agencies, trade associations, research institutes, and manufacturing companies. Ahmad has testified or appeared before commissions in Alberta (Canada), Arizona, Arkansas, California, Colorado, Connecticut, Delaware, the District of Columbia, FERC, Illinois, Indiana, Kansas, Maryland, Minnesota, Nevada, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, ECRA (Saudi Arabia), and Texas. He has presented to governments in Australia, Egypt, Ireland, the Philippines, Thailand and the United Kingdom and given seminars on all 6 continents. His research been cited in Business Week, The Economist, Forbes, National Geographic, The New York Times, San Francisco Chronicle, San Jose Mercury News, Wall Street Journal and USA Today. He has appeared on Fox Business News, National Public Radio and Voice of America. He is the author, co-author or editor of 4 books and more than 150 articles, papers and reports on energy matters. He has published in peer-reviewed journals such as Energy Economics, Energy Journal, Energy Efficiency, Energy Policy, Journal of Regulatory Economics and Utilities Policy and trade journals such as The Electricity Journal and the Public Utilities Fortnightly. He holds BA and MA degrees from the University of Karachi, an MA in agricultural economics and Ph. D. in economics from The University of California at Davis.

Brattle Projects & Research on Electrification

Ongoing

- Forecasting the impacts of new utility initiatives on EV adoption (EPRI)
- System Dynamics based modeling of EV adoption and impacts on utilities (ComEd)
- Developing a framework for evaluating the cost-effectiveness of ratepayer-funded electrification programs (EPRI)
- Reviewing rate design alternatives for public EV fast charging stations (EEI)
- Developing forward-looking ratemaking strategies, including rate design for EVs (GRE)

Recent

- Assessment of the benefits and costs of residential grid-interactive electric water heating (NRECA/NRDC)
- Assessment of the economy-wide technical potential for electrification (Brattle White Paper)
- Exploration of the implications of ride sharing and vehicle automation for electric utilities (Brattle White Paper, Electricity Journal Article, PUF Article)

Additional Brattle Resources

The Electrified Future is Shared, Jürgen Weiss, Public Utilities Fortnightly, PUF 2.0, Mid-February 2018

The electrification accelerator: Understanding the implications of autonomous vehicles for electric utilities, Jürgen Weiss, Ryan Hledik, Roger Lueken, Tony Lee, Will Gorman, The Electricity Journal 30 (2017) 50–57, December 2017

New Sources of Utility Growth: Electrification Opportunities and Challenges; Retail Energy Practice Briefing Series; The Brattle Group, November 2017

Electrification: Emerging Opportunities for Utility Growth, Jürgen Weiss, Ryan Hledik, Michael Hagerty and Will Gorman, January 2017

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- Macroeconomic Impact Modeling
- Rate Design for Electric Vehicle (EV) Charging
- EV Adoption Modeling
- Regulatory Strategy and Support
- Pilot Development

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1214

In the Matter of:	**)**
Application of Duke Energy Carolinas,	**)**
LLC for Adjustment of Rates and	**)**
Charges Applicable to Electric Service	**)**
in North Carolina	**)**

DIRECT TESTIMONY OF
JUSTIN R. BARNES
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT JRB-4

Exhibit JRB-4

I/A

Smart Electric Power Alliance

Residential Electric Vehicle Rates That Work

ATTRIBUTES THAT INCREASE ENROLLMENT

November 2019

In Partnership with:

THE Brattle GROUP

E4 THE FUTURE

enel x

Residential Electric Vehicle Rates That Work

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About SEPA

The Smart Electric Power Alliance (SEPA) is dedicated to helping electric power stakeholders address the most pressing issues they encounter as they pursue the transition to a clean and modern electric future and a carbon-free energy system by 2050. We are a trusted partner providing education, research, standards, and collaboration to help utilities, electric customers, and other industry players across four pathways: Transportation Electrification, Grid Integration, Regulatory Innovation and Utility Business Models. Through educational activities, working groups, peer-to-peer engagements and advisory services, SEPA convenes interested parties to facilitate information exchange and knowledge transfer to offer the highest value for our members and partner organizations. For more information, visit www.sepapower.org. Please contact SEPA at research@sepapower.org for additional information about this report.

About E4TheFuture

E4TheFuture is a nonprofit organization advancing clean, efficient energy solutions. Advocating for smart policy with an emphasis on residential solutions is central to E4TheFuture's strategy. "E4" means: promoting clean, efficient Energy; growing a low-carbon Economy; ensuring low income residents can access clean, efficient, affordable energy (Equity); restoring a healthy Environment for people, prosperity and the planet. Dedicated to bringing clean, efficient energy home for every American, E4TheFuture's endowment and primary leadership come from Conservation Services Group whose operating programs were acquired in 2015 by CLEAResult. Visit www.e4thefuture.org.

About Enel X

Enel X is Enel's global business line dedicated to developing innovative products and digital solutions. Enel X's e-Mobility division is the leading provider of grid-connected electric vehicle charging stations with over 50,000 smart stations across the world. The company's JuiceNet® platform provides smart grid management of EV charging, which is used by thousands of drivers, global automakers, commercial businesses and utilities. In North America, Enel X has ~3,400 business customers, spanning more than 10,400 sites, representing approximately 4.6 GW of demand response capacity and 20+ battery storage projects. For more information please visit www.enelx.com.

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The Brattle Group provides consulting and expert testimony in economics, finance, and regulation to corporations, law firms, and governments around the world. We help energy and utility market participants worldwide anticipate and navigate the challenges and opportunities in changing markets and regulatory environments. Brattle's experts are at the forefront of the latest developments and trends facing the energy industry, and our experience spans the full spectrum of complex, high-stakes matters relating to resource planning and approvals, regulatory policy assessments, rate design, contract litigation, market conduct, performance and enforcement, financial analysis, and mergers & acquisitions. For more information, please visit www.brattle.com.

Authors

Erika H. Myers, Principal, Transportation Electrification, Smart Electric Power Alliance

Jacob Hargrave, Research Fellow, Transportation Electrification, Smart Electric Power Alliance

Richard Farinas, Manager, Research, Smart Electric Power Alliance

Ryan Hledik, Principal, The Brattle Group

Lauren Burke, Senior Director, Marketing & Development, Enel X

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We would also like to recognize Steve Cowell and Pat Stanton with E4TheFuture for their financial and technical support throughout the report development process.

Executive Summary

Electric vehicle (EV) market forecasts predict strong growth in adoption, with much of the associated charging load occurring at home. Utilities can influence home charging behaviors through EV time-varying rates that incentivize residential customers to charge off-peak thereby minimizing distribution system impacts and avoiding the need for costly infrastructure upgrades and investments. This report analyzes residential EV time-varying rates based on survey results from customers and utilities and identifies factors that increase rate enrollment. For the purposes of this report, we included **residential time-varying rates that were identified and marketed as rates specifically available to EV drivers**.

To collect insights on residential EV time-varying rates implemented to date, SEPA worked with The Brattle Group to develop and administer a survey for U.S. utilities that had a qualified rate in-place for at least one year. In addition, to collect insights from EV drivers on time-varying rates, SEPA co-developed a survey with Enel X which was distributed nationwide to the company's JuiceNet-enabled charging station customers.

Why Residential EV Time-Varying Rates Are Important

EVs can use between 3.3 to 20 kilowatts (kW) of electricity, which can exceed the total peak demand of a home in some regions. The increase in peak load can also strain the local distribution system, particularly when several EVs are clustered on single transformers. Residential EV charging load is well-suited to respond to price signals. Most light-duty EVs are parked the majority of the day[1] and can be easily programmed through the car and/or the charger to begin charging at a pre-set time. In the future, it will be desirable to have this and more advanced control capabilities across the grid in a more dynamic framework, in order to respond to real-time market and operating conditions.

As illustrated by our utility and customer survey results, time-varying rates are an effective tool for utilities to influence EV customer charging behavior by incentivizing home charging during off-peak periods. While some industry representatives have questioned the need for EV-specific rates—rates designed for and marketed to EV drivers—to capture benefits, we found that customers on an EV time-varying rate were generally 1) more familiar with the rate rules and 2) more likely to charge off-peak compared to their generic time-varying rate counterparts. EV-specific rates also allow utilities to offer rate options that appeal to a wider range of customer types and preferences across their service territories than they could with only a generic time-varying rate. In the near-term, EV-specific time-varying rates—a form of passive managed charging—offer utilities an effective mechanism to shift residential EV charging behavior to off-peak time periods. The following sections highlight key findings from our research.

Factors that Increase Enrollment

According to the research, certain EV time-varying rate attributes lead to higher customer uptake. Utilities that have a marketing budget for these rates see a 3x increase in enrollment. Further, those using more than three marketing channels have a 1.4x increase in customer enrollment (Figure 1). Utility-driven EV time-varying rate initiatives, as opposed to those required or recommended by customers, governance boards, or legislatures, also have a corresponding 2.4x increase in enrollment. Other important factors include free enrollment and realized bill savings for average EV customers.

Rate Design and Marketing Are Important

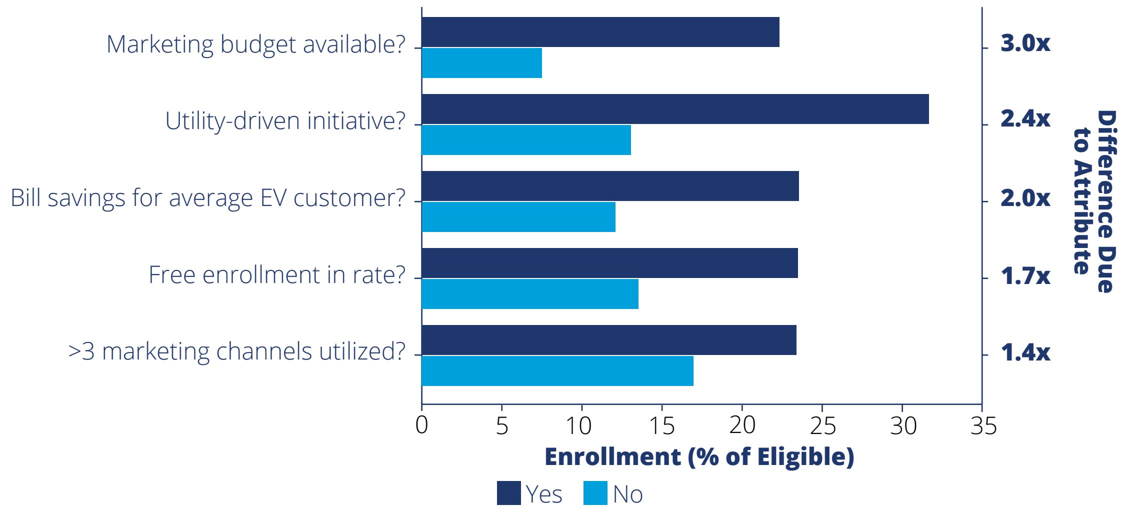
Rate design considerations for time-varying rates, such as bill neutrality, peak/off-peak pricing windows, and peak-to-off peak pricing ratios are also important. An effective rate design conveys price signals that are transparent and actionable, giving customers the necessary information and a strong incentive to shift their charging load from the utility's system peak hours to designated off-peak periods. These factors also directly affect the value proposition for customer enrollment in a time-varying rate. As outlined in this report, the opportunity to reduce their bill is a top motivation for customers. The utility survey results in this report demonstrate that the time-varying rates offered by utilities have successfully shifted charging to off-peak periods, lowering utility bills for the average EV customer.

Further, providing meaningful rate choices, such as offering larger discounts, varied off-peak hours and other significant variations, to customers is more likely to induce higher enrollment and increase off-peak charging behavior. This is reflected in the utility survey results and in the San

1 See Donald Shoup, 2011, The High Cost of Free Parking, which asserts cars are parked up to 95% of the time.

Residential Electric Vehicle Rates That Work

Figure 1: Average Enrollment by EV Time-Varying Rate Attribute



Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=20

Diego Gas & Electric case study summarized in the report. Rate design considerations can include combinations of whole-home and EV-only rates, metering configurations, and off-peak hour definitions that better serve individual customer and grid-wide needs. Dynamic rates, retroactive bill credits via load disaggregation, or subscription rates can also provide more choices and appeal to a broader base of customers compared to straight time-of-use rates, which represent the majority of rates implemented to date.

Marketing directly affects enrollment and need not be expensive. According to the survey, 70% of customers learned about their time-varying rate through low-cost marketing efforts, such as rate information on the utility website. Of survey respondents that didn't enroll in an available rate, it was largely due to their lack of awareness of the rate and the related potential for savings. While customer awareness of EV rates is high, utilities can take measures to improve education and customer understanding of the rates.

Metering Considerations

Metering techniques are important for rate implementation and can determine the difference between a successful program and a program failure. Meter option considerations include the cost of enrollment and equipment, the type of administration, the ease of integration with existing billing systems, the security and reliability of charging signals, and the ability of the program to handle EV technology evolution.

Today, utilities employ at least five metering approaches to implement EV time-varying rates: 1) existing meter, 2) submeter, 3) secondary meter, 4) telemetry in the EV charger, or 5) load disaggregation via data pulled from a meter or other device, such as a meter collar. While the survey didn't identify a correlation between enrollment and a specific metering approach, it is clear from the data that customers want options that minimize enrollment costs. The report provides case studies of innovative rate programs and metering approaches from Indiana Michigan Power (a subsidiary of American Electric Power), San Diego Gas & Electric, Austin Energy, Xcel Energy Minnesota, and Braintree Electric Light Department.

A Bridge to Direct Load Management

As the utility industry builds the capabilities for direct EV charging load control, utilities may be able to leverage the on-board EV batteries for advanced grid benefits. Time-varying rates are an effective first step in developing a strong relationship with EV customers. Creating a positive customer experience with load management is important. Eventually, direct load control can complement time-varying rates and provide more dynamic grid services than can rates alone. Direct load control can also help minimize the challenges posed by the formation of new 'timer peaks' on the distribution system (e.g., if customers begin charging simultaneously when the off-peak window begins, creating a new spike in load).

Beyond EVs, residential demand response and price-responsive controlled usage can also be provided by other equipment, such water heaters, air conditioners, swimming pool pumps, and laundry equipment. As customers become more comfortable with controlled loads through managed EV charging programs, it may also lead to greater acceptance of other utility load-control programs.

Based on our findings, utilities should engage EV customers early to avoid losing customer engagement "momentum." Understanding customer motivation is valuable, and while customers are primarily motivated by savings, a large percentage of customers in our survey are also interested in helping the environment. Describing how load management can lead to increased use of renewable energy and other environmental goals can help utilities increase enrollment and participation in EV time-varying rate programs.

Residential EV time-varying rates can serve as a bridge between passive and active managed charging options by showing customers how, in exchange for providing grid benefits by controlling their charging, they can save money. Utilities should also consider incorporating direct load control with a time-varying rate program. The timing for doing so will depend on EV penetration and the cost-benefit of load management options. Although the need for direct load control may not be immediate, utilities should ensure that equipment installed today is compatible with future pricing and system reliability frameworks by testing options today.

Report Contents

This report provides a comprehensive overview of residential EV time-varying rates and draws conclusions about next steps for residential EV rate design and programs based on the results of a utility survey and a customer survey. The appendices provide a complete list of EV time-varying rates offered by utilities as of September 2019, a list of suggested reading materials, and definitions of time-varying rates. This report was made possible by funding from E4TheFuture and Enel X.

Table 1: Report Roadmap

The Case for Time-Varying Rates	Defines time-varying rate options and describes the benefits and limitations of these rates.
Residential EV Time-Varying Rates Landscape	Describes why utilities are pursuing these rates, how utilities are marketing them, and why customers are interested in residential EV rates.
Consumer Insights	Provides the customer survey results from nearly 3,000 EV drivers who have either 1) enrolled in a time-of-use (TOU) program or 2) had a utility TOU rate option available, but chose not to enroll.
Features of Effective EV Time-Varying Rates	Highlights the utility survey results to identify the features of rates and programs that contribute to the highest customer enrollment.
What To Do About Metering	Highlights utility metering approaches, the pros and cons of each, and outlines case studies of utilities that have developed innovative rate programs through various metering approaches.
Conclusion	Recommendations for utilities as they consider options for EV time-varying rates and describes other research topics to explore, as the industry continues to investigate load management strategies.
Appendices	▪ Appendix A includes a complete list of EV time-varying rates ▪ Appendix B includes suggested reading materials ▪ Appendix C includes expanded definitions of time-varying rates and illustrations

Source: Smart Electric Power Alliance, 2019.

1) Introduction

Electric vehicles (EVs), in certain regions of the U. S., are quickly becoming one of the largest flexible loads on the grid. Depending on vehicle type, a single EV represents from 1.4 kW to 20 kW of instantaneous load[2], or 500 to 4,350 kWh/year of energy consumption.[3] This is similar to the impact of introducing air conditioning systems and electric water heaters decades ago. As of July 2019, customers have purchased over 1.28 million EVs in the United States,[4] consuming an estimated 4.97 terawatt-hours (TWh) per year.[5]

EV adoption is expected to increase as vehicle prices decline and new models become available. Navigant forecasts that EVs in the U.S. will reach over 20 million in 2030 with an energy consumption of 93 TWh.[6] According to forecasting models by the National Renewable Energy Laboratory (NREL), electrified transportation may result in between 58 to 336 TWh of electricity consumption annually by 2030, depending on the speed and type of vehicle deployment.[7] This represents the equivalent average annual energy consumption of 5.6 million to 32.3 million U.S. homes.[8]

Forecasts predict that much of the future charging load will occur at home, as it does today. Utilities can strongly influence residential charging behavior by incentivizing their customers to charge off-peak to minimize distribution system impacts and avoid the need for costly infrastructure upgrades and investments. As described in the 2019 SEPA report, *A Comprehensive Guide to Electric Vehicle Managed Charging*, this is known as managed charging.

There are two forms of managed charging: passive and active.[9] Passive managed charging uses behavioral load control strategies, including rates and incentives, to influence customers. Active managed charging is direct load control enabled through the charger, the vehicle, or some other interface that can remotely control a charging event to respond to real-time grid conditions.[10]

This report presents empirical evidence regarding the effectiveness and benefits of passive managed charging via time-varying rates for residential EV customers. In the near-term, passive managed charging offers utilities an effective strategy for shifting residential EV charging behavior to off-peak time periods that can effectively lead to more sophisticated active managed charging programs, as discussed in Chapter 2.

In order to collect insights on residential EV time-varying rates implemented to date, SEPA collaborated with The Brattle Group ("Brattle") to develop and administer a survey ("utility survey") for all U.S. utilities that had a qualified rate for at least one year. Further, to collect insights from EV drivers on time-varying rates, SEPA co-developed a survey with Enel X (formerly known as eMotorWerks) which was distributed nationwide to the company's JuiceNet-enabled charging station customers ("customer survey"). Additional survey information is provided in the research methodology.

2 Using Level 1 to Level 2 charging stations; Direct Current Fast Charging (DCFC) load would be higher.
3 SEPA, 2019, *A Comprehensive Guide to Electric Vehicle Managed Charging*.
4 Electric Drive Transportation Association, July 2019, https://electricdrive.org/index.php?ht=d/sp/i/20952/pid/20952
5 Assumes 3,858 kWh per EV per year based on data from the U.S. Department of Energy Alternative Fuels Data Center. Assumes all vehicles sold since 2010 are still operating in the U.S.
6 Navigant forecast provided in April 2019 to SEPA staff. See also: EEI/IEI, November 2018, *EV Sales Forecast and the Charging Infrastructure Required through 2030.*
7 National Renewable Energy Laboratory, 2018, *Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States*, https://www.nrel.gov/docs/fy18osti/71500.pdf.
8 Based on 2017 U.S. Energy Information Administration data that residential U.S. electricity consumers used an average of 10,400 kWh per year. See https://www.eia.gov/tools/faqs/faq.php?id=97&t=3.
9 Note: other terms used for managed charging include smart charging, V1G, intelligent charging, direct load control, or passive load control.
10 Additional information about active managed charging can be found in SEPA's 2019, *A Comprehensive Guide to Electric Vehicle Managed Charging* report.

Research Methodology

SEPA collected primary research data from electric utilities that have developed time-varying rates for EV customers. The majority of the rates currently offered by the sampled utilities are time-of-use (TOU) rates. SEPA contacted 50 utilities, of which 28 responded to the survey with a total of 40 EV specific time-varying rates. Of the 28 utilities, 19 were investor-owned, 4 were municipally owned, 4 were member-owned cooperatives and one was a community choice aggregator.

The SEPA survey team employed best practices to maximize response rates, and performed data verification and validation with survey respondents while collaborating with Brattle to analyze the results.

Brattle's analysis focused on identifying factors that contribute to a "successful" EV TOU rate. For the purposes of this analysis, "success" is defined as a high enrollment rate or significant shifting of load to desirable (i.e., lower-priced off-peak) periods. The load shifting data indicates that the TOU rates shifted the majority of charging to off-peak hours. Estimates of rate enrollment were significantly more varied. Brattle's analysis limited consideration of the survey responses to those that would be useful for analyzing drivers of high enrollment. They eliminated survey responses that appeared to be duplicates, where rates had expired, and where enrollment estimates were not provided. Survey responses were reviewed and assigned to specific categories relevant to the quantitative analysis (e.g., assigning a "yes" or "no" flag based on whether or not a utility indicated that budget was available to market the rate). Average enrollment was calculated for each specific category (e.g., average enrollment among those utilities that had a marketing budget versus those that did not). The averages were calculated as a simple average across utilities, rather than weighting by number of customers which would skew the results to the findings of larger-sized utilities. A statistical technique known as "lasso analysis" was then applied to empirically estimate the relative importance of each factor in driving higher enrollment in the TOU rates.[11] Brattle shared their insights with SEPA for the purposes of developing the report.

Concurrent with the utility survey, Enel X and SEPA developed and distributed a customer survey which generated 2,967 US-based responses from JuiceNet users. This provided data on EV customer familiarity with their rate structure and behavioral energy insights. JuiceNet respondents represented a wider customer sample beyond the utilities included in the SEPA/Brattle survey. Many of Enel X's customers reside in California, where close to half of the nation's EVs are located and where residential TOU rates will be the default rate within investor-owned utility service territories. Nearly 50% of respondents to Enel X's survey (1,422 out of 2,967 respondents) live in California. Further, since the survey only sampled the customers of one EV charging manufacturer, the pool of respondents may reflect customers that were specifically interested in the JuiceNet smart charging features.

2) The Case for Time-Varying Rates

As EV adoption grows, significant load will be added to the grid. If customers charge their EVs during peak demand hours, this increase in demand could create unwelcome effects. One way to minimize peak load impacts is through the use of time-varying rates. This section defines time-varying rate options and describes the benefits and limitations of these rates.

A. What Are Time-Varying Rates?

For much of the day, less than half of the electric grid's capacity is being used. This is because the grid is designed to handle peak demand.[12] As a result, reducing the peak—during which the generation and delivery of electricity is more costly—is advantageous for both the utility and customer, as it minimizes the system costs and therefore

11 Least Absolute Shrinkage and Selection Operator (LASSO) is a technique used to improve the prediction accuracy of regression models by identifying a subset of covariates (i.e., model variables) that generally have the most predictive value.

12 Girouard, Coley., 2015, *Time Varying Rates: An Idea Whose Time Has Come?*, https://blog.aee.net/time-varying-rates-an-idea-whose-time-has-come.

the electricity rate ultimately charged to customers. By pricing electricity higher at times when demand is at its peak, customers are incentivized to shift their use to off-peak times, minimizing their electricity use when it matters most to the grid. Rates with prices that vary throughout different hours of the day or days of the week are known as time-varying rates.

The benefits of time-varying rates to utilities and customers are not limited to aligning rates more closely with the underlying costs associated with generating and delivering electricity. Time-varying rates are also an effective tool for motivating customers to shift their energy usage to off-peak or other desirable time periods to help achieve certain grid outcomes, such as renewable energy integration. For example, time-varying rates can help utilities maintain grid stabilization by signaling lower prices to customers for hours during which there is a significant amount of uncurtailable renewable generation.

While a form of time-varying rates—TOU rates—have been offered by utilities for decades, the recent increase in consumer adoption of distributed energy resources has spurred a new wave of rate offerings, including those specifically designed for EV customers.

Definition of EV Time-Varying Rates

For the purposes of this report, we included residential time-varying rates that were identified and marketed as rates specifically available to EV drivers. Often, these rates have specific off-peak or super off-peak windows designed to accommodate the charging duration needs of EVs and to incentivize charging during designated off-peak periods. The rates are sometimes—though not always—limited to EV drivers. Some of these rates apply to the customer's entire home energy usage, while other rates are specific to the customer's EV charging load. There are instances where an EV TOU rate looks similar in design to a generic TOU rate and is marketed as an EV rate. The authors used the rate title and descriptions developed by the utilities to identify the residential EV rates listed in Appendix A and the utility survey outreach contact list.

A typical on-board EV charger consumes about 3.3 to 9 kilowatts (kW) of demand, which can exceed the total peak demand of a home, depending on the region. Level 2 charging loads for vehicles with larger battery packs can be up to 20 kW.[13] A concern utilities face, as the penetration of EVs continues to increase, is the potential for the clustering of EVs in certain sections of the distribution system. If an EV cluster develops on a particular feeder, it could become overloaded and result in the need for costly repairs and upgrades by the utility. Time-varying rates offer utilities a potential solution by incentivizing customers to shift their EV charging load from peak to off-peak time periods, during which feeders have more available capacity and are less likely to become overloaded.

Residential EV charging load is well-suited to respond to price signals.[14] Most light-duty EVs are parked the majority of the day and overnight[15] and can be easily programmed through the car and/or the charger to begin charging at a pre-set time. Time-varying rates are an effective tool to incentivize customers to shift their charging to off-peak periods, as confirmed by our utility and customer survey findings.

In this report, time-varying rates are placed in one of seven categories: Time-of-Use, Subscription Rates, Off-Peak Credits, Real Time Pricing (RTP), Variable Peak Pricing (VPP), Critical Peak Pricing (CPP), and Critical Peak Rebates (CPR):[16]

- **Time-of-Use Rates** typically have two or more price intervals (e.g., peak, off-peak, super-off-peak) that differ based on levels of demand observed throughout the day. Sometimes, these prices vary by season, but both the prices and the designated price interval hours for each tier remain constant.
- **Subscription Rates** allow customers to pay a fixed monthly fee for electricity and other utility-provided services in exchange for unlimited consumption during specified hours of the day or days of the week.
- **Off-Peak Credits** can take the form of a fixed or variable incentive provided as a rebate or a bill credit in exchange for restricting consumption to designated hours of the day or days of the week.
- **Real Time Pricing (RTP)** are variable, hourly prices determined either by day-ahead market prices or real-time spot market prices.

13 SEPA, 2019, *A Comprehensive Guide to Electric Vehicle Managed Charging*, see Table 1.

14 Multi-Unit Dwelling (MUD) customers may face different considerations than typical residential customers when responding to time-varying price signals. For example, tenants residing in MUDs may share common EV chargers and would likely not have equal access to the chargers during lower-priced off-peak time periods. This could result in potential access and equity issues based on the schedules of each tenant.

15 See Donald Shoup, 2011, *The High Cost of Free Parking*, which asserts cars are parked up to 95% of the time.

16 Definitions adapted from: Environmental Defense Fund, 2015, *A Primer On Time-Variant Electricity Pricing*, https://www.edf.org/sites/default/files/a_primer_on_time-variant_pricing.pdf. Subscription Rates and Off-Peak Credits are not discussed in the EDF primer.

- **Variable Peak Pricing (VPP)** is a hybrid of TOU and RTP, with price intervals (e.g., peak, off-peak) that are constant like a TOU rate but allow for the price charged during the peak tier to differ day to day.
- **Critical Peak Pricing (CPP)** has a higher rate at designated peak demand events (also called "critical events") on a limited number of days during the year to reflect the higher system costs during these hours.
- **Critical Peak Rebate (CPR)**, also called Peak Time Rebate (PTR), is the inverse of CPP. Utilities pay customers a rebate for each kWh of electricity they reduce during peak hours of peak demand events.

The latter four rate structures are known as "dynamic pricing" because the price signals are not static and more closely reflect the real-time market conditions. Some of these rate options can be combined on a single rate schedule. For example, a number of utilities offer customers a rate schedule which pairs a TOU rate with a CPP component.

Further details about time-varying rate options and illustrations are provided in Appendix C.

B. Benefits of Time-Varying Rates

Time-varying rates are successful in altering customers' charging habits. Benefits of shifting charging habits via rates, as defined by the Environmental Defense Fund[17] and others include:

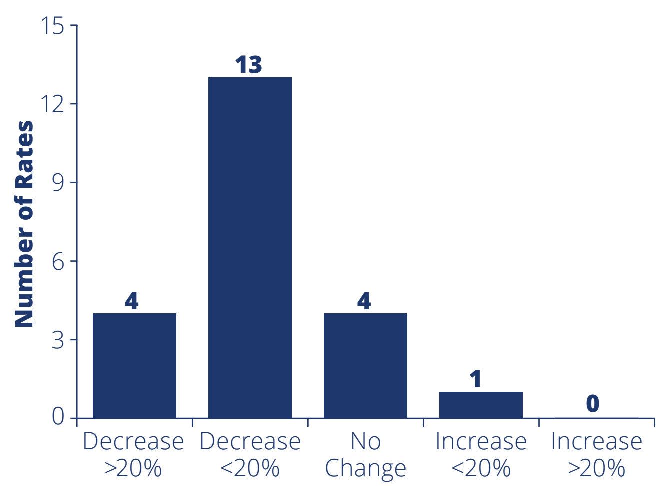
- Reducing energy supply costs by making greater use of lower-cost resources and limiting the use of the highest-cost energy;
- Reducing pollution by shifting demand to times when clean energy sources are generating electricity;
- Providing economic benefits to all utility customers through the grid efficiencies captured using off-peak charging;
- Avoiding or deferring capacity investments in generation, transmission, and distribution;
- Reducing the cost of infrastructure upgrades/replacement/repairs, particularly transformers;
- Responding to customer needs, incentivizing customer EV adoption, and influencing beneficial customer charging behavior; and
- Encouraging sustainable behavior changes, resulting in more reliable, predictable, and pronounced peak load reductions for utilities.

While some industry representatives have questioned the need for EV-specific rates to capture these benefits, our customer survey found those on an EV TOU rate were 1) more likely to charge off-peak a greater percentage of the time compared to their generic TOU rate counterparts and 2) more familiar with the rate rules (see "Customer Insights" chapter).

With the proper rate structure, utilities can use EV specific rates to provide load management, generate cost savings for EV owners, encourage more off-peak charging, and increase customer satisfaction (as indicated by enrollment length). These benefits are verified by responses to the utility survey, including:

- Utilities reported, on average, more than 90% of customers responded to the off-peak price signal.[18]
- The majority of utility respondents saw their average EV customer's charging bill decline (see Figure 2).
- Approximately 40% of utilities surveyed reported persistent changes in charging behavior after the introduction of EV time varying rates.[19]

Figure 2: Change in Customer EV Bill After Enrolling in EV Rate



Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=30
Note: Six respondents indicated that the bill change was 'unknown'.

17 Environmental Defense Fund, 2015, *A Primer On Time-Variant Electricity Pricing*, https://www.edf.org/sites/default/files/a_primer_on_time-variant_pricing.pdf

18 Results from utility survey respondents. N=15

19 Results from utility survey respondents. N=29

- Utilities also saw a high level of retention on their EV rate, with over 95% of participants who were enrolled at the beginning of the year remaining enrolled at the end of the year.[20]

A 2014 San Diego Gas & Electric EV pricing pilot[21] found that EV owners were highly responsive to modest price signals and even more so to higher price ratios. Customers exposed to a price ratio of 1-to-1.2-to-2 (super-off-peak to off-peak to peak hours) shifted 73% of their charging to the super-off-peak period, while customers exposed to a price ratio of 1-to-2.4-to-3.8 (super-off-peak to off-peak to peak hours) shifted 84% of their charging to the super-off-peak period. The degree of load shifting increased consistently over the study horizon as customers became more familiar with the time-varying rate. This evidence of customer price-responsiveness is consistent with the customer survey results as discussed in the "Customer Insights" chapter of this report.

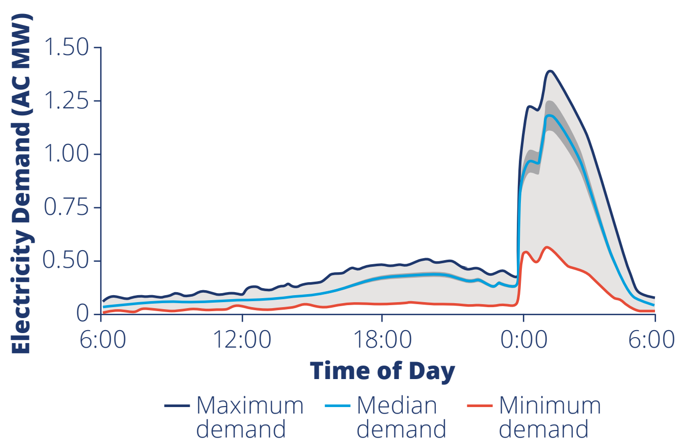
C. Considerations for Time-Varying Rates

While time-varying rates can provide a range of system benefits, they can also present operational challenges, particularly when applied to EV charging. Some concerns exist regarding the potential for households to program their EVs to begin charging exactly at the same off-peak time, leading to a new load "spike" (also known as a "timer peak") during these off-peak hours as illustrated in Figure 3. At the local distribution level, the result could be a new peak that would contribute to capacity constraints, the effect of which could be exacerbated by geographically clustered EVs. This issue was discussed at length in the SEPA report, *A Comprehensive Guide for Electric Vehicle Managed Charging*.[22]

Similarly, FleetCarma found in a 2019 study that static residential TOU rate structures reduce variability but can cause unintentional coincident load.[23] Innovative rate design practices, such multiple pricing intervals that gradually increase the price from the off-peak period over several hours, could help to address this concern. It is, however, an issue that could warrant more active management of charging load as EV adoption increases.

Active managed charging, which enables the utility or another third party to shift charging loads to reduce potential distribution system impacts and better align charging with lowest-cost electricity and renewable generation (e.g., during wind or solar peaks) could provide additional benefits. Beyond EVs, residential demand response and price-responsive controlled usage can also be provided by other equipment, such water heaters, air conditioners, swimming pool pumps, and laundry equipment. Gaining customer comfort with controlled loads, such as enrollment in an EV managed charging program, may contribute to greater acceptance of other programs.

Figure 3: Illustration of San Diego Gas and Electric Weekday "Timer Peak"



Source: MJ Bradley & Associates, 2017[24]
Note: This is a rendition of the original graphic.

As part of a comprehensive EV strategy, utilities should identify the stage gates at which they can introduce active managed charging in addition to passive managed charging programs, such as a time-varying rate. The timing of an active managed charging program will depend on several variables, including the penetration of EVs in a utility service territory (especially among those that can shift loads) and the cost-benefit of load management options. While the exact parameters of this transition are not yet fully defined, from a qualitative perspective, it may resemble Table 2. As an example, utilities in states

20 Results from utility survey respondents. N=16

21 Nexant, February 2014, *Final Evaluation for San Diego Gas & Electric's Plug-in Electric Vehicle TOU Pricing and Technology Study*. https://www.sdge.com/sites/default/files/SDGE%20EV%20%20Pricing%20%26%20Tech%20Study.pdf

22 Smart Electric Power Alliance, May 2019, *A Comprehensive Guide to Electric Vehicle Managed Charging*, www.sepapower.org.

23 FleetCarma, 2019, *EV Profile & Manage EV Charging Load For Demand Response*, https://www.fleetcarma.com/docs/ProfileandManage2019-FleetCarma-web.pdf&sa=D&ust=1565040346133000&usg=AFQjCNGcJrPwvJjBb1wDd4vihfFWAh_m8w

24 MJ Bradley & Associates, April 2017, *Electric Vehicle Cost-Benefit Analysis*, https://mjbradley.com/sites/default/files/CO_PEV_CB_Analysis_FINAL_13apr17.pdf

like Hawaii and California facing rapid growth in EVs, high amounts of distributed solar, and higher electricity costs may achieve greater grid benefits through an active managed charging solution than through a traditional TOU rate.

Residential EV time-varying rates could serve as a bridge between passive and active managed charging options. As customers begin their EV journey, building a high level of trust between the customer and the utility is essential to the success of active managed charging. Customers don't buy EVs to provide grid support; however, if they had a positive load management experience using time-varying rates, they may be more likely to consider an active managed charging program.

American Electric Power (AEP) and its subsidiaries, are planning to leverage their existing utility smart meter networks to enable EV-only TOU rate offerings and implement an active load management program as highlighted in the case study in Chapter 6.

Table 2: Potential Residential EV Load Management Options Based on Utility System Conditions

EV Load Management Option	Penetration of Light-duty Residential EVs	Available Distribution Capacity (including substations/ transformers/ feeders)	Integration of Intermittent Loads (e.g., solar, wind)	Cost of On-Peak Electricity
Passive				
Behavioral Load Control (e.g., text message during system peak)	Low	High	Low	Average
Generic Time-of-Use Rate	Low	High	Medium	Above average
Generic Dynamic Pricing Rate	Low	High	High	High
EV Time-of-Use Rate	Medium	Medium	Medium	Above average
EV Dynamic Pricing Rate	High	Medium	High	High
Active				
Managed Charging (designed to minimize distribution impacts)	High	Low	High	Above average
Managed Charging (designed to minimize on-peak electricity costs)	High	Medium	High	High
Vehicle-to-Grid	High	Low	High	High

Source: Smart Electric Power Alliance, 2019.

3) Residential EV Time-Varying Rates Landscape

Utilities are introducing residential EV time-varying rates with a variety of design features, configurations, and marketing strategies. This section identifies the current rates landscape, why utilities are pursuing them, how utilities are marketing them, and the levels of customer interest in residential EV rates.

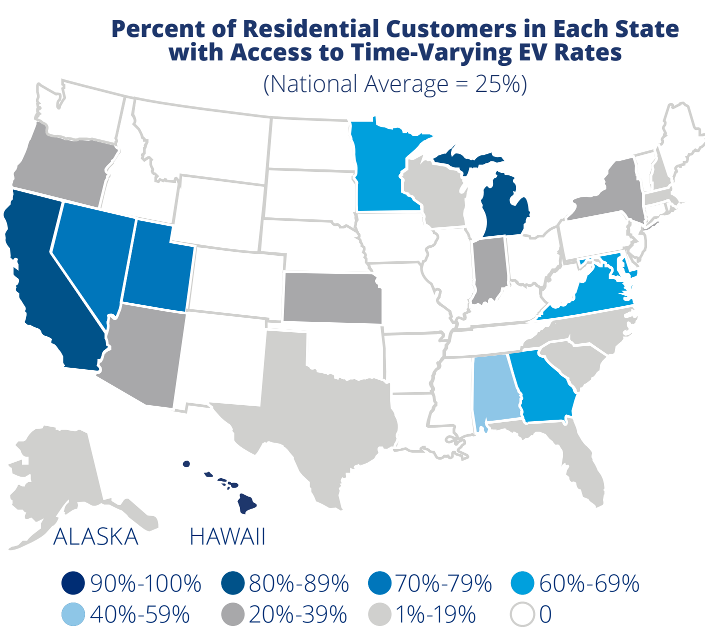
A. Current Status

With the expanded adoption of residential advanced metering infrastructure (AMI), many utilities so-equipped are offering at least one residential time-varying rate. As of 2017, approximately 9% of U.S. utilities and energy suppliers offered a residential time-varying rate with over 6.5 million customers enrolled.[25]

As of September 2019, SEPA and Brattle identified 64 active residential EV rates being offered by 50 utilities.

The landscape of residential EV time-varying rate offerings is changing quickly with the majority of these rates introduced in the past few years. Figure 4 illustrates where these residential EV time-varying rates are located and the share of residential customers with access. It also highlights observations about these rates. Table 3 provides specific insights into the EV time-varying rates provided by the utility survey respondents.

Figure 4: Characteristics of Active Residential EV Time-Varying Rates



28 investor-owned utilities, **12** municipal utilities, and **10** electric cooperatives

18 pilot programs, **46** fully implemented residential rates

Of the 64 EV rates, **58** were TOU rates, **1** was a subscription rate with an on-peak adder, and **5** were off-peak credit programs.

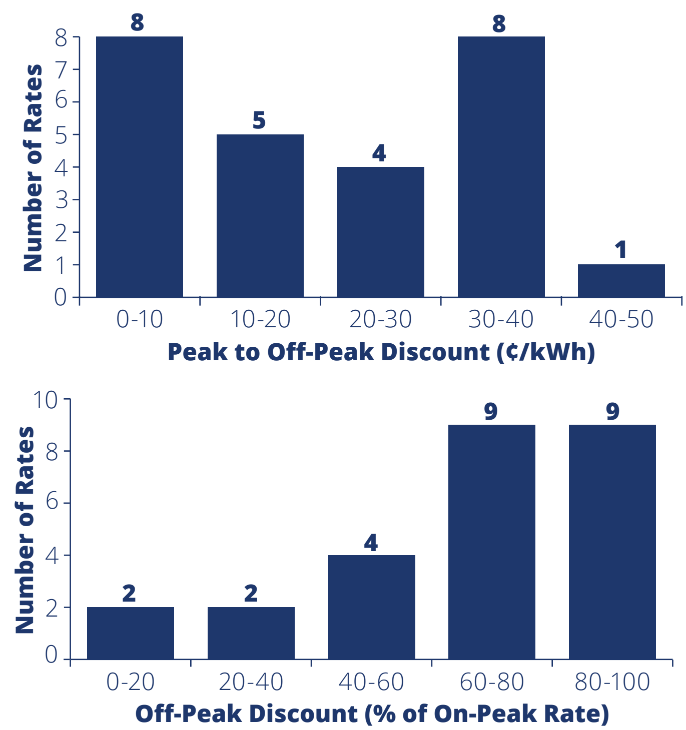
How the rate applies to the home load:

- **35** rates apply to the **total household energy consumption**, including the EV charging load.
- **21** rates **apply strictly to EV charging**. These rates typically require the installation of a second meter or submeter, and two rates are metered from a submeter in the EV charger itself.
- **8** rates allowed customers to **choose between whole home or EV-only options**.

Source: Smart Electric Power Alliance & The Brattle Group, 2019.

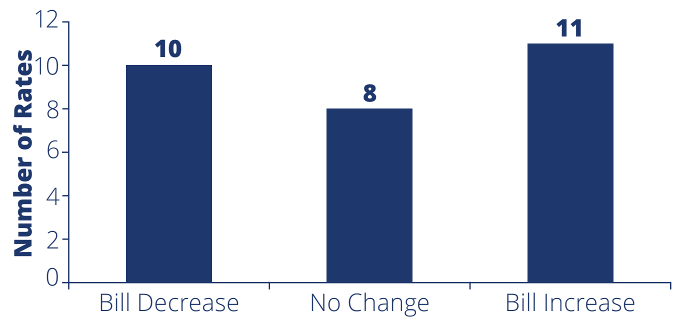
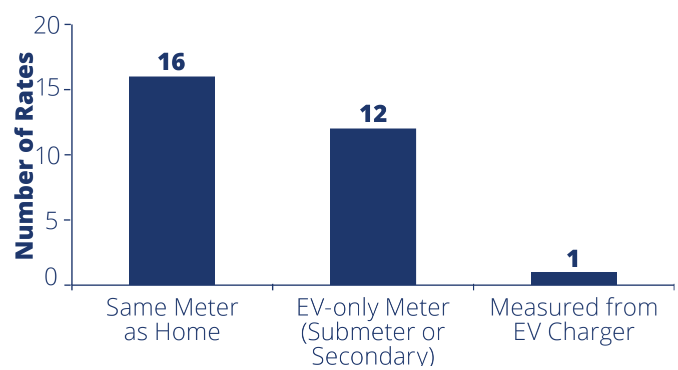
25 U.S. Energy Information Administration, Form EIA-861, 2017. https://www.eia.gov/electricity/data/eia861/. A total of 310 EIA electric power industry survey participants had residential time-varying rates with customers enrolled, in a population of 3,421 utilities and nontraditional entities such as energy service providers. Includes 290 entities with residential TOU rates, 14 with real time pricing, eight with variable peak pricing, 25 with critical peak pricing, and 12 with critical peak rebates. Note that Form EIA-861 does not include Subscription Rates and Off-Peak Credits as forms of time-varying rates.

Table 3: Insights from Utility Survey Respondents with EV Time-Varying Rates

Utility Motivations for Offering Rate	Utilities designed the rates to: ▪ **Encourage charging during low or negatively-priced wholesale power hours**, such as when renewable generation is being curtailed. ▪ **Discourage charging during specific times** when the distribution system is constrained. ▪ **Encourage EV adoption by lowering the overall total cost of ownership**.
Rate Design Features	The TOU rate offerings in the survey differ significantly across design features such as: ▪ The **peak-to-off-peak price ratio**. Several pilot programs have begun testing rates with significant differentials between the peak and off-peak period, such as peak-to-off-peak price ratios in excess of 10-to-1. ▪ **Number of pricing periods.** ▪ The **timing** of those periods. ▪ **Seasonality.**
Peak-to-Off-Peak Price Ratios	The price ratios of the rates varied from 1.2-to-1 to 15.5-to-1, with a **median of 3.6-to-1**. Similar variation is observed in the absolute price differentials, which range from $0.02 per kWh to $0.44 per kWh, with a **median of $0.20 per kWh**. Figure 5 illustrates the peak to off-peak discount in cents per kWh as identified by the utility survey. **Figure 5: Peak to Off-Peak Discount by Cents/kWh and Percent of On-Peak Rate**  Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=26.

Residential Electric Vehicle Rates That Work

Table 3: Insights from Utility Survey Respondents with EV Time-Varying Rates (Continued)

Bill Neutrality Is Not a Standard Feature	Approximately one-third of the time-varying EV rates analyzed in the utility survey would provide an average participant with bill savings compared to the default rate, even in the absence of changes in charging behavior. For the other two-thirds, the customer's bill would remain the same or increase if charging load was not shifted to the off-peak period. Rates offering bill neutrality or savings encourage enrollment, however, as Figure 6 shows, this is not a standard feature. **Figure 6: Expected Bill Impact for EV Customer if Enrolled in EV Rate Without Change to Charging Pattern**  Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=29.
Upfront Customer Costs	Despite potential savings, **some customers are deterred by the initial enrollment fees** for the installation of additional metering equipment (e.g., second meter, submeter, meter collar, EVSE). Some utilities socialize those expenses as part of a broader EV program so the customer enrollment fee is less of an issue for participants.
Cost Savings	Most of the rates are **more advantageous for flexible loads such as EVs** (including customers willing to shift EV charging to off-peak periods) **than the otherwise applicable residential rate**, offering significant savings opportunities through cheaper off-peak rates and reduced or eliminated rate tier(s).
Rate Enrollment rRequirements	In some cases, rate enrollment was required for customers to receive **utility-sponsored EV rebates or utility-financed charging infrastructure**.
Metering Configurations	Metering configurations varied widely with a majority being applied to the whole home (Figure 7). **Figure 7: EV Rate Metering Configuration for Utility Survey Respondents**  Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=29.

Source: Smart Electric Power Alliance, 2019

Innovative Rate Example: Free Energy! Cobb EMC NiteFlex Rate

Cobb Electric Membership Corporation in Georgia created a unique rate to incentivize EV owners to shift their charging to off-peak hours. Using the NiteFlex rate, customers can recharge their EV during super off-peak for free for the first 400 kWh per month.[26] The rate is split into three tiers with peak, off-peak, and super off-peak times:

- The **peak** rate ($0.1350/kWh) is between 1pm - 9pm.
- The **off-peak** rate ($0.07181/kWh) is between 9pm - Midnight and 6am - 1pm.
- The **super off-peak** rate is between Midnight - 6am where the initial 400 kWh are free, and any additional usage is at a rate of $0.045/kWh.

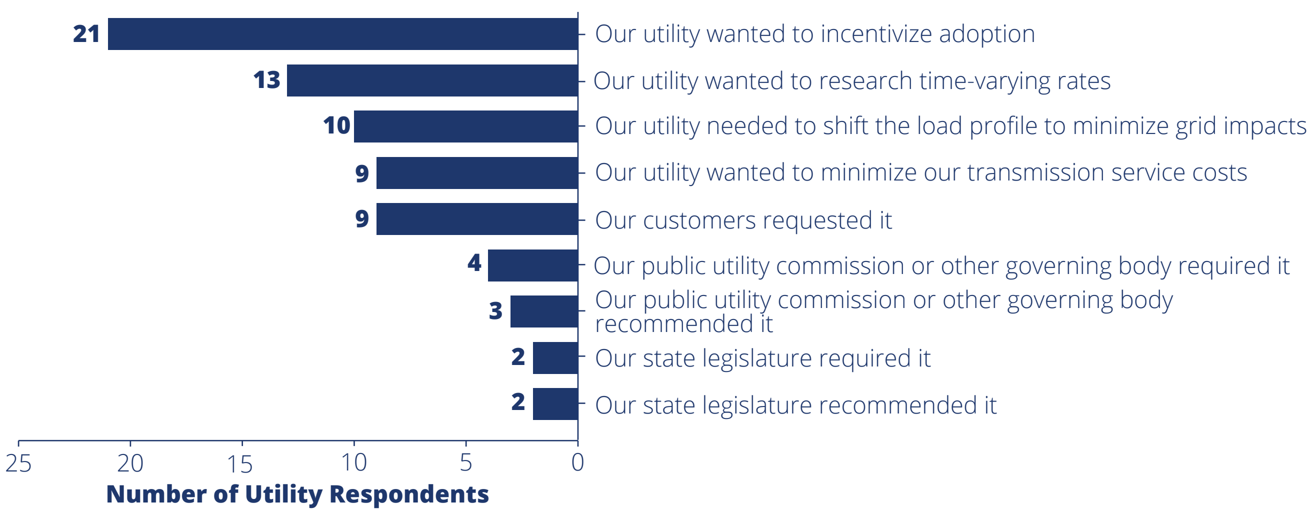
In addition to EVs, this rate also applies to other smart appliances or energy loads that can be shifted to later hours.

B. Why Are Utilities Pursuing EV Time-Varying Rates?

In response to the increased customer adoption of light-duty residential EVs, utilities have been developing and offering their customers EV time-varying rates. As Figure 8 shows, the four most commonly cited reasons were to incentivize (in the context of encouraging and promoting) EV adoption, research time-varying rates, shift the load profile, or minimize transmission costs. Less than half the utilities offering residential EV time-varying rates did so because their customers requested it or because the utility governance board or legislative body required or recommended it. Additional insights about utility motivations and lessons learned are included in the chapter, "Features of Effective EV Time-Varying Rates."

Respondents indicated that customers with Level 2 chargers and battery electric vehicles (BEVs) were more likely to enroll in an EV time-varying rate. Though the reasons weren't captured in the utility survey, higher enrollment for customers with Level 2 chargers and BEVs could be due to the amount of energy required to charge larger batteries leading to potentially higher bill savings. Knowing that enrolled customers are highly motivated by saving money, these larger savings may drive BEV customers to enroll. This may indicate that as more customers purchase BEVs over plug-in hybrid electric vehicles (PHEVs), the pool of potential EV rate customers will grow.

Figure 8: Reasons Utilities Created EV Time-Varying Rate



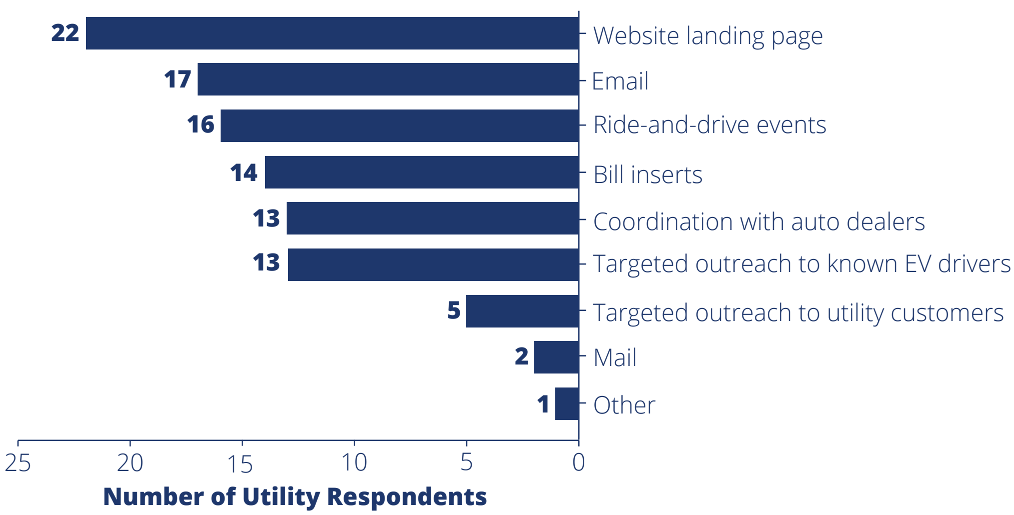
Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=29. Respondents selected all that applied.

26 Cobb EMC, 2019, NiteFlex Rate, https://www.cobbemc.com/content/niteflex.

C. How are Utilities Marketing EV Time-Varying Rates?

A wide range of methods are used to market the EV rates. Utilities typically used more than one method, favoring the easiest and lowest-cost solutions such as a website landing page and emails (Figure 9). Ride-and-drive events are also popular among utilities; however, as discussed in the "Consumer Insights" chapter, ride-and-drive events may be less successful at recruitment.[27] Bill inserts, coordination with auto dealers, and targeted outreach to known EV drivers are also common strategies.

Figure 9: Utility EV Rate Outreach Methods



Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=29. Respondents selected all that applied.

D. Consumer Interest in EV Rates

A recent report, *Rate Design: What Do Consumers Want and Need?*[28], by the Smart Energy Consumer Collaborative (SECC), a nonprofit that has been researching consumers' energy-related needs and wants since 2011, identified interest in EV rates from residential customers. SECC surveyed consumers from two types of rate states:

- **Alternative rate states**[29] offer rates beyond flat rates including TOU, interruptible load, VPP, CPP, RTP, net energy metering, low-income subsidies, and green power plans. These states include California, Wisconsin, Oklahoma, Delaware and the District of Columbia.
- **Traditional rate states** offer flat rates, flat progressive (include pricing tiers that increase in price with volume) rates, and flat regressive (including pricing tiers that decrease in price with volume) rates. These include all remaining states divided between the Northeast, Midwest, South and West.

When customers were asked to rate their interest on a scale of 0-10, with 0 meaning "not at all" and 10 meaning "very interested", respondents gave an average of 6.2 across all states (Table 4).

Interest did not vary significantly from state to state; however, different segments of the population had widely varying levels of interest (Table 5). Green Innovators and Tech-savvy Proteges both indicated an above average level of interest.[30]

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27 A possible reason for this difference in data could be that utilities with higher enrollment were more proactive in outreach, and ride-and-drive events were a part of that outreach. The apparent success of ride-and-drive events from the utility's perspective could merely be a sign of the utility's overall more effective methods of outreach.

28 The full versions of SECC's research reports are available exclusively to members of the organization. Learn more about membership at smartenergycc.org.

29 Alternative rate states were defined by SECC and described in the report research methodology.

30 See also: *SECC, Consumer Pulse and Market Segmentation—Wave 7*, 2019. https://smartenergycc.org/consumer-pulse-and-market-segmentation-wave-7-report/.

Table 4: Residential Interest in EV Rate Plans, by State Type

State Type	States Include	Customer Interest	# Responses
Alternative Rate State	California, Wisconsin, Oklahoma, Delaware and the District of Columbia	6.2 out of 10	N=546
Traditional Rate State	All remaining states that are not alternative rate states	6.0 out of 10	N=592
All States	All states	6.2 out of 10	N=1,138

Source: Smart Energy Consumer Collaborative, 2019.[31]

Table 5: Residential Interest In EV Rate Plans, by Segment

Segment	Characteristics	Customer Interest	# Responses
Green Innovators	Lead the way in energy conservation. They are primarily middle aged (40%, 35–54) and evenly split gender-wise. They are more likely to have a post-secondary education. The combination of high education and being established in their career corresponds with another segment characteristic — they have the highest incomes. In fact, one-in-five households has a six-figure income.	7.1 out of 10	N=278
Tech- Savvy Proteges	Consumers who have the skill set and interest to save energy but need a push to take action. This segment is more likely to be male and younger. One-third are aged 18–34. Half have a post-secondary education and live with three or more people. Despite having the highest employment rate (67%), they are more likely to be middle-income earners. While they have the highest homeownership rate, they are also the most transient — half have moved cities in the past five years.	6.5 out of 10	N=392
Movable Middle	Straddles most metrics and are neither tuned-out nor highly engaged. Demographically, the Moveable Middle skews older and they're more likely to be retired. They have lower incomes and are less educated than the Green Innovators and Potential Proteges we have discussed. These consumers like to stay put—70 percent have not moved in the past five years, and over half live in an older home.	5.8 out of 10	N=262
Energy Indifferent	The oldest group of consumers overall. One-third are retirees aged 65+ and most have no post-secondary education. They are cost conscious. Many live in energy inefficient older homes, but because they have fewer appliances, their energy bills are relatively low.	4.7 out of 10	N=206

Source: Smart Energy Consumer Collaborative, 2019.[32]

31 SECC, 2019, *Rate Design: What Do Consumers Want and Need?*

32 Ibid.

This SECC research also shows a high level of interest in EV rates among certain segments of the population, which aligns with the customer types most interested and knowledgeable about EVs produced from additional SECC research in 2016 (Table 6). We would anticipate interest in EV rates to increase as more consumers become aware of the technology. However, in the near-term, customer segmentation should be considered as part of any outreach and marketing strategy.

Table 6: Level of EV Interest Defined by Consumer Segment

Segments	Perspectives	Key Demographics	Awareness and Interest in Solar/EV
Green Champions	"Smart energy technologies fit our environmentally aware, high-tech lifestyle."	Youngest, more likely to be college-educated	Relatively highest levels of solar and EV, nearly four times the interest level of Status Quo.
Savings Seekers	"How can smart energy programs help us save money?"	Younger, more likely to be college-educated	Lower level of awareness and interest in all types of solar and EV.
Status Quo	"We're okay; you can leave us alone."	More likely middle age, lower income renters, living in non-single family dwellings, less likely to be educated	Relatively lowest level of awareness and interest in all types of solar and EV.
Technology Cautious	"We want to use energy wisely, but we don't see how technologies can help."	Most likely homeowners who are older in age, less likely to be college-educated	Marginally higher than Savings Seekers on awareness and moderate interest in solar and EV.
Movers & Shakers	"Impress us with smart energy technology and maybe we will start to like the utility more."	More likely middle age, higher income, singe-family homeowners, college-educated	High levels of awareness comparable to Green Champions on average, but moderate interest levels in solar and EV.

Source: Smart Energy Consumer Collaborative, 2016.[33]

4) Consumer Insights

To identify what customers want from time-varying EV rates[34] and why they may have not participated in available utility rate options, the project team developed a customer survey that was sent nationwide to existing Enel X JuiceNet charger customers. This survey gathered nearly 3,000 responses.[35] The vast majority of those sampled said their utility offered a TOU rate (Figure 10). A very low number of EV drivers (10%) were not aware if the utility offered a TOU rate, signifying that the sample was knowledgeable about their utility rate options.

Many of Enel X's customers reside in California, where close to half of the nation's EVs are located and where residential TOU rates are becoming the default rate for residential customers in the Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric service territories.[36] Nearly 50% of respondents to Enel X's survey (1,422 out of 2,967 respondents) live in California. This report isolates the California population from the rest of the survey sample to minimize any survey bias. Not surprisingly, 90% of the California survey population reported having an

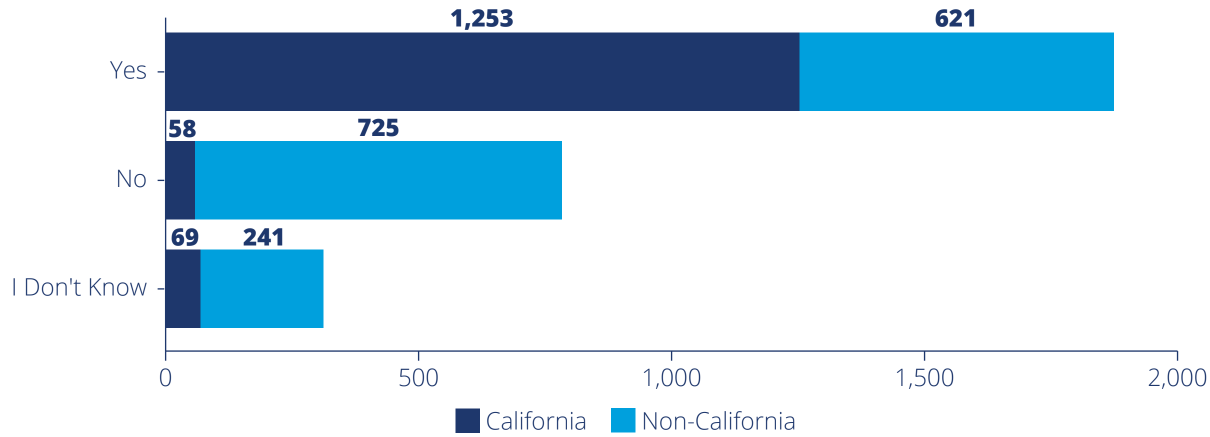
33 SECC, 2016, *Consumer Driven Technologies.*

34 Since the vast majority of time-varying rates currently offered to customers are TOU, we specifically used the term "time-of-use rates" in the survey to minimize customer confusion.

35 Non-U.S. respondents were removed from the sample prior to analysis.

36 Residential customers of these utilities currently have access to an optional TOU rate.

Figure 10: EV Customers with a TOU Rate Option (California and Non-California), by Total



Source: Smart Electric Power Alliance & Enel X, 2019. N=2,967.

available TOU rate. Nearly 40% of the non-California survey population had access to a TOU rate.

Survey Results: Enrolled TOU EV Customers and Non-Enrolled EV Customers

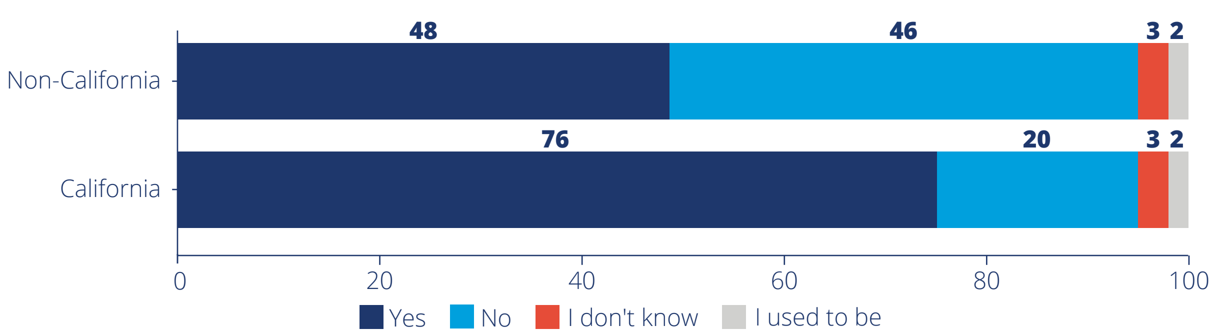
This section analyzes the survey results from two populations of EV driver groups (a total of 1,783 respondents)[37] that had an available utility TOU rate option: 1) enrolled customers and 2) customers that chose not to enroll in a TOU rate, which we term as non-enrolled.

The enrolled customers provided a variety of insights into their motivations, to what type of rate they subscribed (including generic and EV TOU rates), their level of familiarity and participation in the rate, and how they heard about the rate initially. For non-enrolled customers, the survey identified why they didn't participate and what it would take to change their mind.

A. Insights from Enrolled Time-of-Use Rate EV Customers

Among our sample, over 65% of participants in the customer survey said they are currently enrolled in their utility's TOU rate (Figure 11). Among the sample, 75% of California respondents were enrolled and nearly 50% of non-California respondents were enrolled. Of those who are enrolled in a TOU rate, 39% indicated that their TOU rate is EV-specific (Figure 12)—42% for California respondents and 30% for non-California respondents. Only 2% of EV drivers for both populations were enrolled in a

Figure 11: EV Customers Enrolled in a TOU Rate, by Percent



Source: Smart Electric Power Alliance & Enel X, 2019. N=1,880.

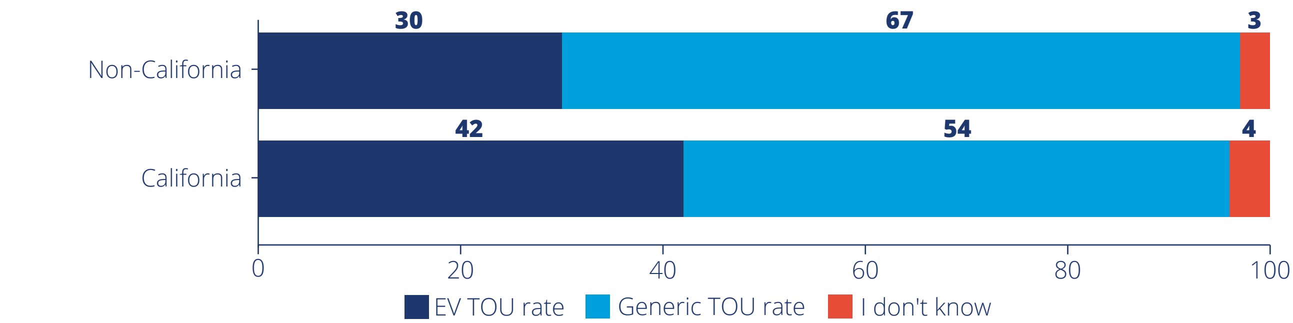
37 This population does not include respondents that did not know if they were enrolled or that were previously (and not currently) enrolled in a TOU rate.

TOU rate, but are no longer. This would suggest that once a customer enrolls, they remain on the rate.

Similar to the results from the utility survey, the Enel X survey respondents reported high levels of behavior shifting, with 87% of consumers charging off-peak 95% to 100% of the time (Figure 13). Respondents on an EV TOU rate were only slightly more likely to charge off-peak compared to their generic TOU counterparts. Perhaps more interesting, 7% more EV rate customers (including CA and non-CA) participated 100% of the time compared to the generic TOU population. This suggests that customers enrolled in a TOU rate understand how to participate and show a willingness to adjust their charging behavior.

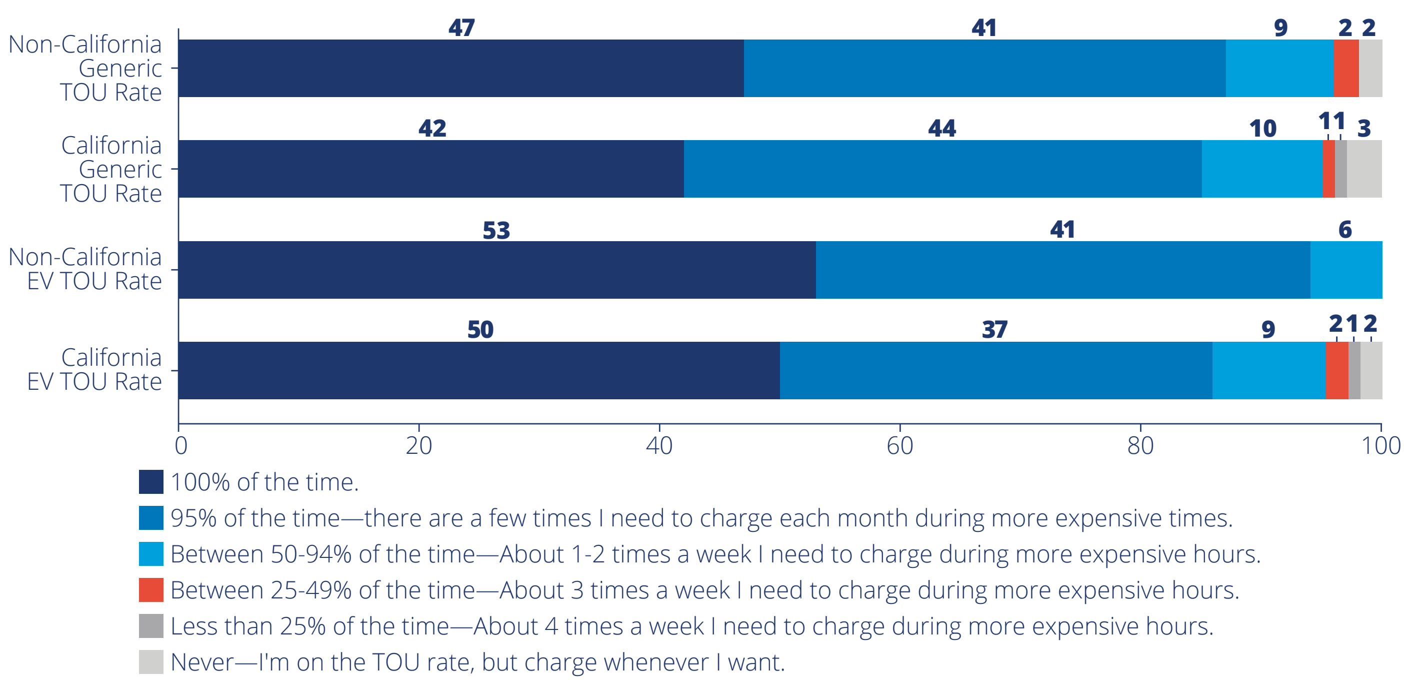
When asked how familiar the EV driver was with the rules around their EV rate, 86% (including CA and non-CA) indicated they were extremely familiar to somewhat familiar. Interestingly, EV drivers on the EV TOU rate were more familiar with their rate rules by nearly 10% (including CA and non-CA) compared to those on a generic TOU rate (Figure 14). While familiarity with these rates was high, these results suggest that utilities could do more to help their customers navigate the rules of the program—particularly with the 'somewhat familiar' group.

Figure 12: EV Customers Enrolled by TOU Type (EV or Generic), by Percent



Source: Smart Electric Power Alliance & Enel X, 2019. N=1,241

Figure 13: Average TOU Enrolled EV Customer Charge Time Done Off-Peak by TOU Type (California and Non-California), by Percent

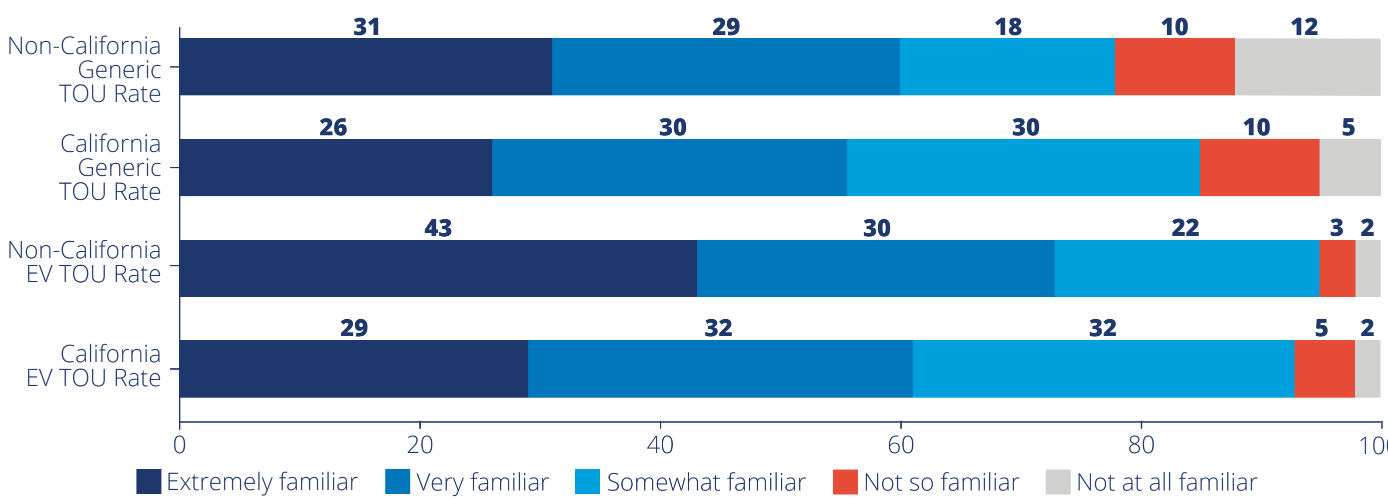


Source: Smart Electric Power Alliance & Enel X, 2019. N=1,167.

When respondents were asked why they enrolled in the TOU rate, 86% (including CA and non-CA) enrolled to save money (nearly 3x more than the next option) and for environmental benefits (Figure 15). Drivers on the EV TOU were 5 percentage points (including CA and non-CA) more motivated by savings than their counterparts on the generic TOU rate. Key for utilities is that while customers are primarily motivated by savings, environmental considerations are also important—by speaking to both of these motivations in program design and marketing campaigns, utilities can appeal to a wider range of customer types and interests.

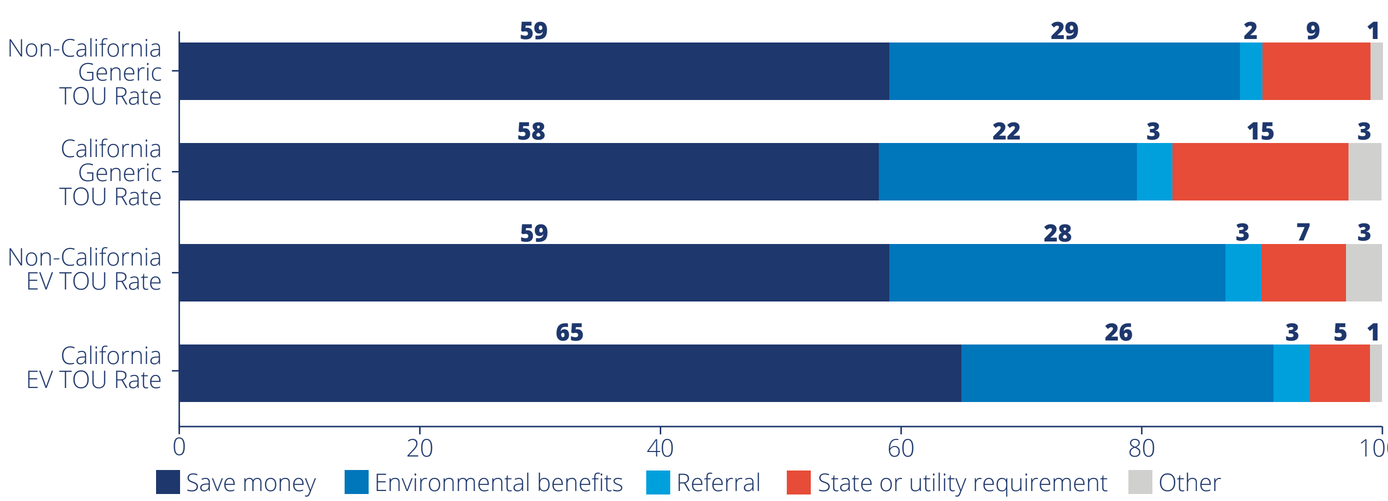
Survey respondents discovered their TOU rate through methods that are inexpensive and easy for utilities to use. Almost 70% discovered the rate through the utility website, bill inserts or flyers, and emails (Figure 16). Only 0.6% (10 out of 1,679) customers discovered their TOU rate through a ride-and-drive event. EV TOU rate participants relied more heavily on information from the utility website and through referrals than their generic TOU counterparts. There was not a significant difference between California and non-California respondents.

Figure 14: Enrolled EV Customer Familiarity with TOU Rate Rules by TOU Type (California and Non-California), by Percent



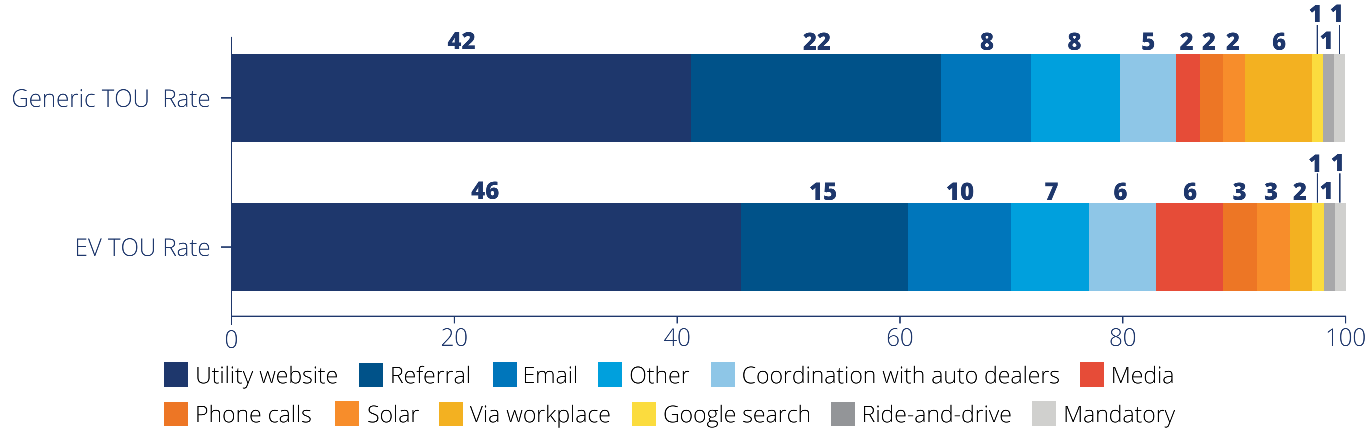
Source: Smart Electric Power Alliance & Enel X, 2019. N=1,107.

Figure 15: Motivation for EV Customer to Enroll by TOU Rate Type (California and Non-California), by Percent



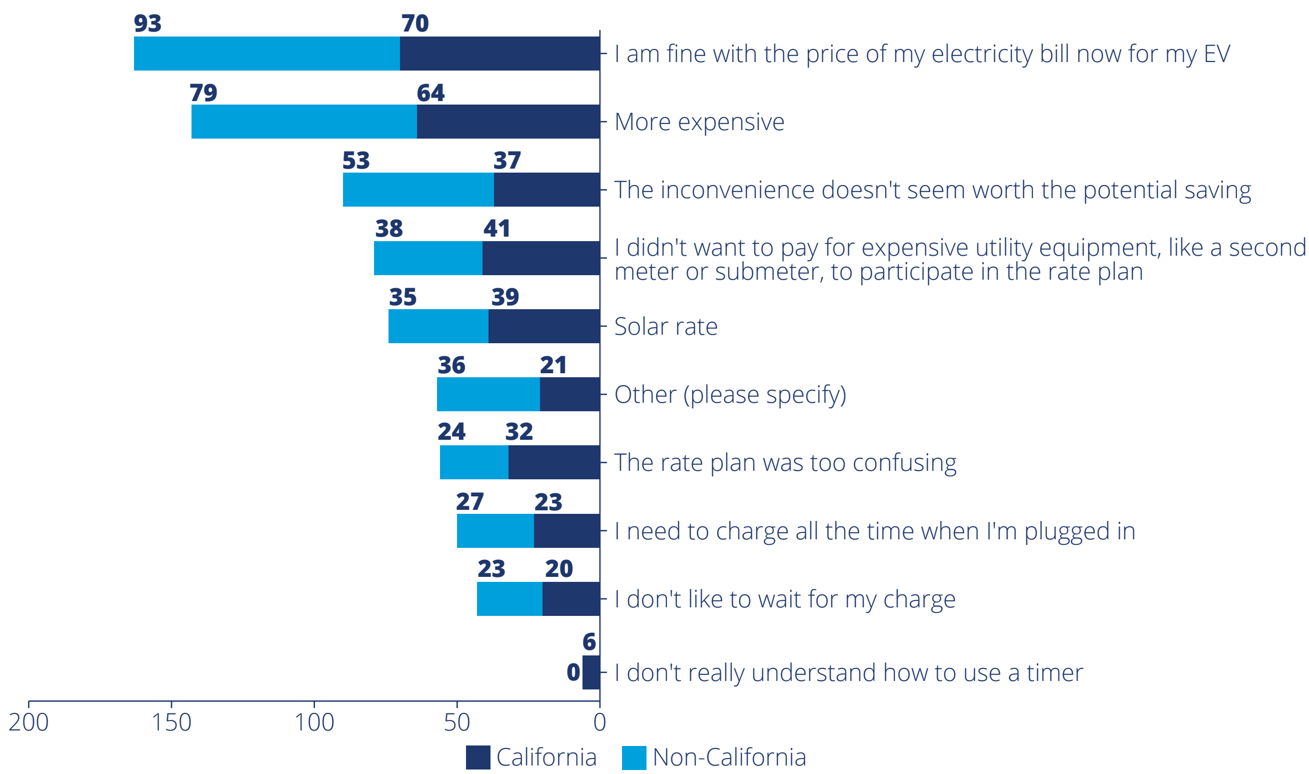
Source: Smart Electric Power Alliance & Enel X, 2019. Respondents selected all that apply. N=1,192. (1,704 options selected)

Figure 16: How Enrolled EV Customers Heard About the TOU Rate by Type, by Percent



Source: Smart Electric Power Alliance & Enel X, 2019. Respondents selected all that apply. N=1,173. (1,611 options selected)

Figure 17: Why EV Customers Did Not Enroll in a TOU Rate, by Total



Source: Smart Electric Power Alliance & Enel X, 2019. N=526. (761 options selected)
Respondents selected all that apply.

B. Insights from Non-Enrolled EV Customers

When EV drivers were asked why they didn't enroll in a TOU rate, responses indicated insufficient savings and inconvenience (Figure 17).

Regarding insufficient savings, many did not want to pay for expensive utility equipment, they thought the rate would be more expensive, or they would not save enough money due to their electricity usage behavior. Others indicated that they were satisfied with the current price of their electricity bill. Many also didn't like the inconvenience of waiting for their charge or needed to charge frequently. Responses also indicated confusion about the rate, how to use timers, and conflicts with other existing rates, like solar rates.

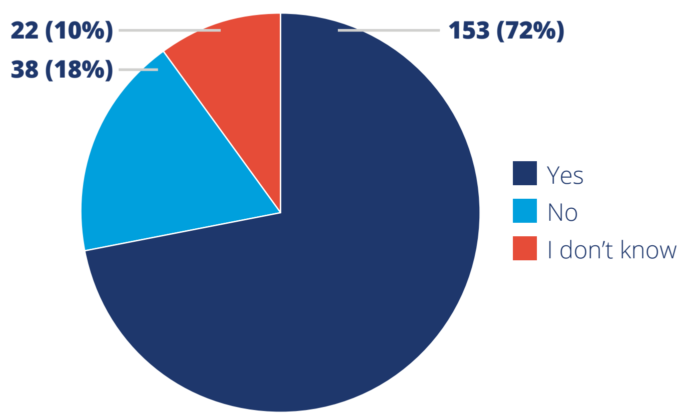
According to the survey, over 72% of non-enrolled customers were willing to charge their EV during off-peak hours (Figure 18).[38] If customers are willing to charge off-peak, but are not sufficiently incentivized by the potential savings, there must be a significant deterrent to enroll. A factor could be the perceived inconvenience of enrollment and compliance with the rate or insufficient financial incentive, as indicated in Figure 19.

Approximately 50% of respondents indicated they would need a savings of $100 or more per year to persuade them to enroll in a TOU rate, though the survey results also indicate that consumer preferences vary and not all customers are equally motivated by savings. Customers seeking more savings through their applicable rate may prefer a time-varying rate with a larger peak to off-peak ratio that offers a higher financial reward for shifting their charging to off-peak periods. Alternatively, as shown by Figure 17, some customers may be deterred by a perceived inconvenience of a time-varying rate with a higher peak to off-peak ratio or a limited off-peak period time window for cheaper charging rates. These findings suggest that it is difficult for utilities to appeal to all different customer types with only one rate design as discussed in the 'What to do about Metering' chapter.

By offering customers multiple rate options with significant variation, utilities may engage broader segments of their customer base and achieve higher enrollment rates.

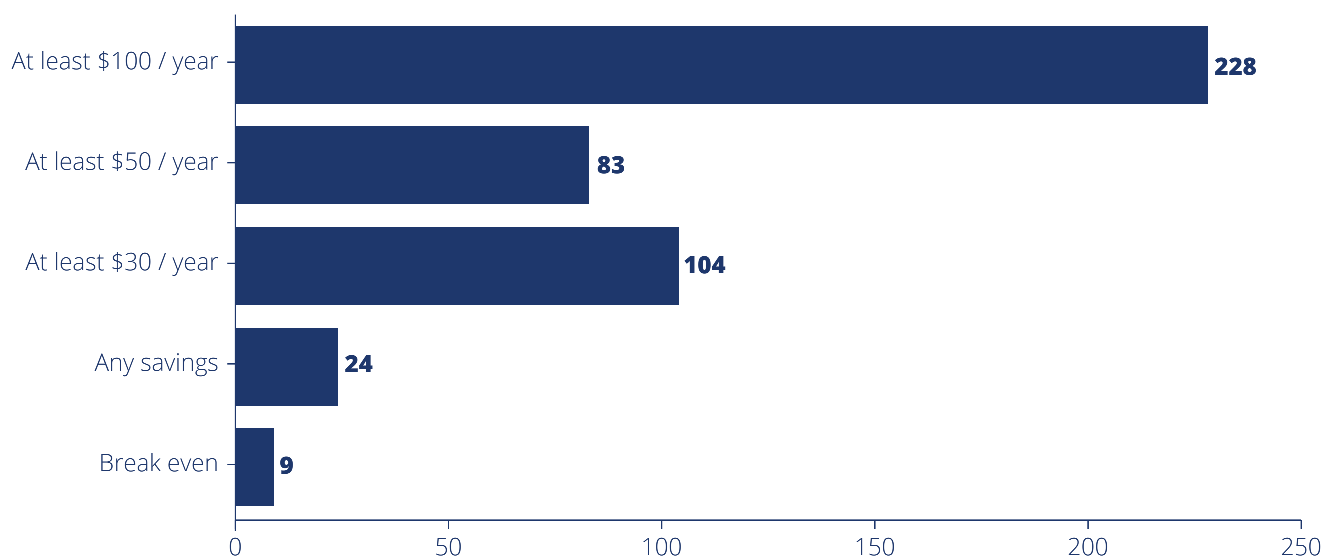
Utilities can employ behavioral programs as an alternative or supplement to a time-varying rate, in order to encourage more customer off-peak charging. Load management may be achieved through a variety of behavioral programs such as email and text alerts or education campaigns. These programs would require nominal utility investment.

Figure 18: Non-Enrolled EV Customers Willing to Charge Off-Peak, by Percent and by Total



Source: Smart Electric Power Alliance & Enel X, 2019. N=213.

Figure 19: Savings Required for EV Customers to Enroll in a TOU Rate, by Total



Source: Smart Electric Power Alliance & Enel X, 2019. N=448.

38 Note: The survey did not ask if customers were aware of the applicable off-peak hours as part of the available TOU rate.

5) Features of Effective EV Time-Varying Rates

This section summarizes the features of EV rates that contribute to the highest levels of customer enrollment. Data on customer enrollment was obtained through the utility survey, with information collected for 20 active, full-scale (excluding pilots) rate offerings. Nearly half (9 of 20 rates) reached enrollment levels of at least 25% (Figure 20). However, variation in enrollment levels is significant, ranging from less than 1% up to 80% of eligible customers (with 80% represented by Braintree Electric Light Department and highlighted in the case study in Chapter 7). Most rates in the utility survey had been offered for between two and five years with an average age of four years.

A. Utility Survey Findings

The survey identified a number of variations in rate design and marketing. Based on analysis by Brattle, some of these characteristics correlate to enrollment. Figure 21 highlights five of the attributes with the strongest relationship to high enrollment levels. In order of most-to-least influential:

1. Rates with an available **marketing budget** have enrollment 3x greater than those without (22% vs. 7%).
2. Rates driven by a **utility initiative** had significantly higher average enrollment than those offered to satisfy legislative or regulatory requirements or customer demands. Utility-driven initiatives had enrollment of over 30% compared to less than 15% for others;
3. **Rates providing bill savings** (in the absence of adjustments to charging behavior) have enrollment levels 2x higher than those with an expected bill increase;
4. Rates with **free enrollment** and no additional metering cost have enrollment 1.7x higher than rates with an additional cost to enroll; and
5. Rates that were promoted using **four or more marketing channels** have enrollment 1.4x those using three or fewer marketing channels.

These findings are intuitive, but many of the existing time-varying EV rate offerings identified in the utility survey did not include these attributes.

The length of time the rate was offered is not a relevant contributor to its achieved enrollment. Average enrollment is similar for rates that have been offered for at least four years (26%) compared to those that have been offered for less than four years (23%) (Figure 22). Offering a rate for a long period of time is not sufficient to attract customer enrollment. Rather, higher enrollment is driven by actively promoting the rate to customers through specific marketing initiatives.

According to the survey, ride-and-drive events and coordination with auto dealers were two marketing tools most significantly related to higher enrollment levels (see Figure 23). The consumer survey would indicate that ride-and-drive events were less helpful in discovering an EV rate, but this may be due to the limited number of utilities that currently offer them limiting the sample population with the opportunity to participate in an event. It's important to note that those utilities offering ride-and-drive events are using other marketing channels as well. As such, it was difficult to determine a cause and effect relationship specifically related to ride-and-drive events.

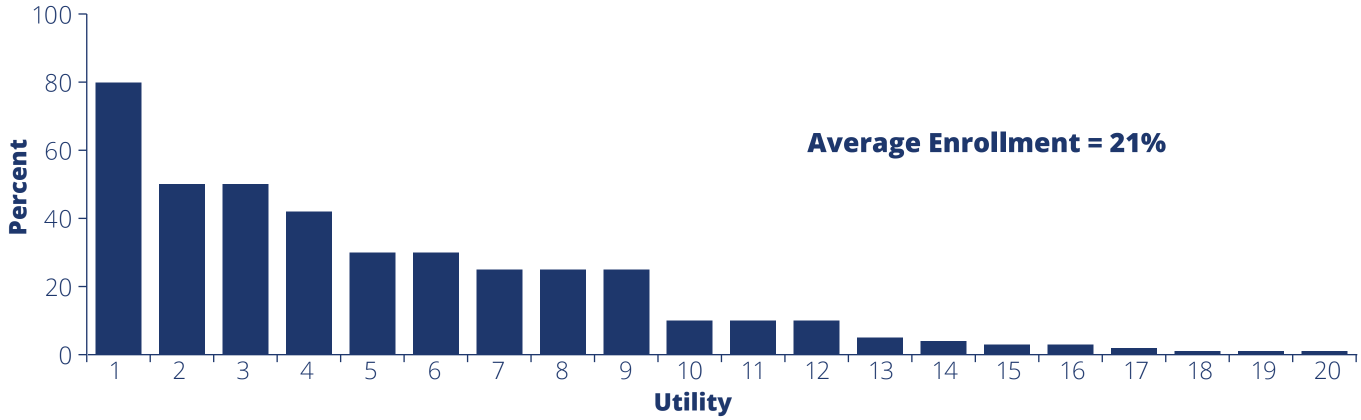
B. Utility Lessons Learned

Utility survey respondents offered lessons learned, primarily regarding customer interest, marketing, rate design considerations, and metering (discussed further in Chapter 7). EV rate design practices are in the formative stages, and the experiences of utilities with EV rates provide unique and useful insights. The following summarizes these perspectives; varied experiences sometimes produce conflicting insights.

Customer Insights and Marketing

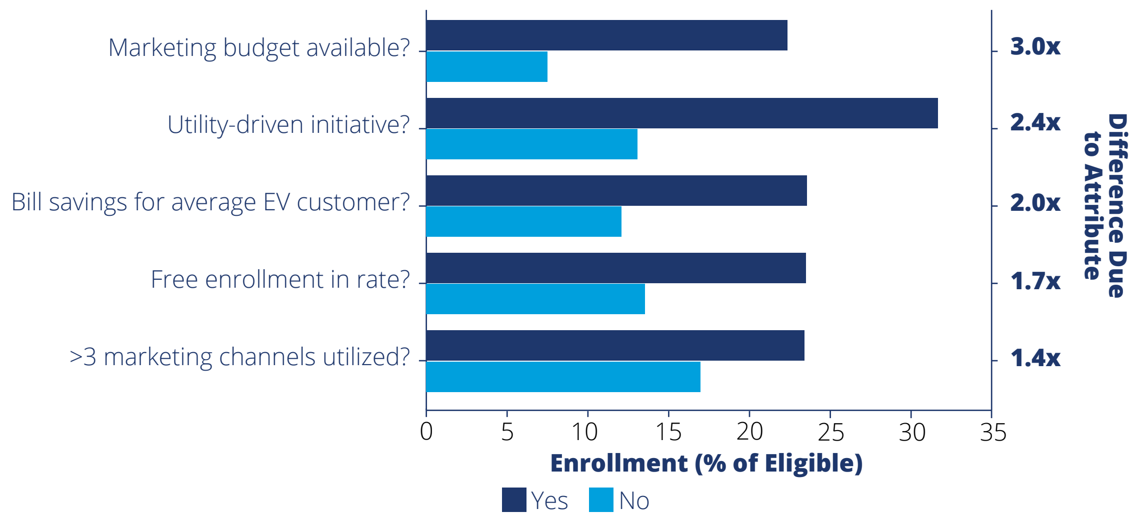
- Customer communication is key. Utilities should not depend on third-parties, such as dealers, to provide utility rate information.

Figure 20: Share of Eligible EV Customers Enrolled in the EV Rate



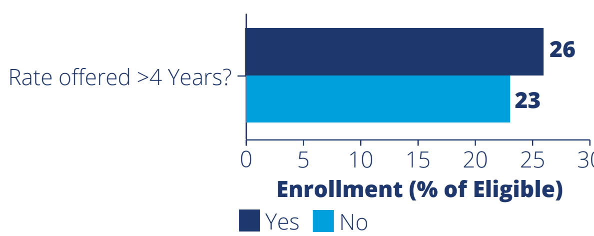
Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=20.

Figure 21: Average Enrollment by Attribute



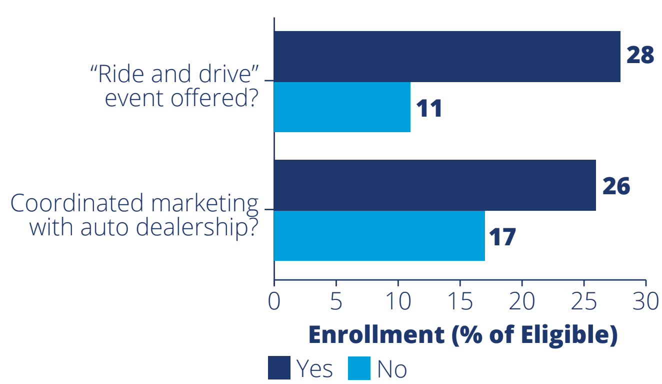
Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=20

Figure 22: Rate Offering Duration Is Not a Factor in Enrollment Success



Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=20.

Figure 23: Rate Marketing Efforts Are Important



Source: Smart Electric Power Alliance & The Brattle Group, 2019. N=20

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- Creative recruitment is required, as enrolling customers is very challenging, even with large incentives and attractive rates.
- One western state utility experienced, "consistently high enrollment in their EV rate over the last 4-5 years, with approximately 25% of EV owners enrolled. This occurred with little active marketing, illustrating that customers (at least early adopters) are interested in saving on fuel costs."
- While some utilities see EV rates as a way to promote EV adoption, one utility suggested that their in-state tax credit was a bigger sales incentive. The rate might encourage those customers to charge at night, but in their state, EV sales were driven mostly by state tax incentives. Further, other rates offered by the utility (e.g., a demand rate) could yield better savings for EV drivers.
- One utility said, "customers are very satisfied with the EV rate and change their charging behavior to maximize their savings. Promote/publicize the EV rate in every way possible and practical to inform the public."

Rate Design

- One utility indicated a need to closely consider the number of hours for the off-peak rate and the price differential between the off-peak and super off-peak. In their case they had six hours in the super off-peak, but that customers preferred eight.
- One utility stated, "Customers are apprehensive to sign up for a rate that applies to their whole house usage as opposed to just their EV charging behavior." Other utilities felt the opposite was true, due to customer apprehension about additional metering costs.
- Utilities also recommended building flexibility into the rate to accommodate changing grid conditions, such as a shift in the timing of the net system peak demand due to growing solar PV adoption.
- Though some utilities are concerned about eroding profitability through favorable off-peak pricing, one utility stated, "Even with a fairly high on-/off-peak differentials, enough usage occurs during peak that revenue is not as severely compromised as some expected."
- As previously noted, the cost to participate is a major factor in enrollment. One utility stated, "Customers are sensitive to up-front costs to participate in the program."
- Another utility found that a one-size-fits-all approach will not work. They suggest giving customers options that help them save money on their EVSE and metering costs. They also suggested using company-provided electricians to help customers set the charging schedule on their vehicles or in the chargers, which increased the possibility of 96% off-peak charging.
- From one utility's perspective, they thought a discount during off-peak hours was a better alternative than increasing the price during the peak period.

Metering

- Utilities had varying opinions about the most effective way to meter and bill customers under a time-varying EV rate. One utility felt that submeters were the most effective metering method for EV time-varying rates given the wide variety of charging equipment options available to customers. Another utility felt that a submetered rate was successful at influencing charging behavior, but at a cost to the customer and the utility. They stated, "Managing that cost will be the primary hurdle to deploying submetering. It is still unclear how much more effective a submetered rate would be at influencing behavior when compared to a whole house rate." A different utility suggested to not mandate a submeter, which for them, resulted in hundreds of extra dollars in cost of installation. They felt that a better alternative was to "require a smart EV charging station that could communicate and send the utility the off-peak usage data to provide an 'incentive' check each month or quarter."
- A utility shared on second service metering options, "a separately metered EV rate is largely unpopular among EV owners. The added cost, time, and effort of adding a separate service is not attractive, and there are not easily apparent savings compared to the whole-house rate, which had similar pricing."
- Another utility stated that due to the unpopularity of the up-front costs for second service, they were piloting other services/technologies, though "the second service is the more economic option.. [for example] cases with detached garages and a fully loaded existing service panel in the customer's home."
- "Whole house EV rates seem successful at influencing behavior, but prevents visibility into specific charging behavior. These rates are relatively straightforward to deploy," was the opinion of another utility.

Notably, the top three drivers of time-varying EV rate enrollment are all factors the utility can control, including:

1. **Residential EV rates that offer customers the opportunity for savings compared to the standard rate:** EV rates must provide customers with an opportunity for financial savings, in order to be attractive to customers. Rates should be designed such

that the price signals are transparent and actionable, so customers have the information necessary and a sufficient incentive to shift their charging load to designated off-peak periods. Rates that are successful in encouraging off-peak charging behavior lower the utility's cost to serve, resulting in lower prices for customers.

2. **No additional metering charge or customer investment required:** The up-front costs associated with any of the metering options, for example a second meter or a submeter, was identified by several utility survey respondents as a deterrent to enrollment. One option to overcome this barrier is to include the customer's entire home load under the time-varying rate, minimizing the initial investment. However, some customers may not want to subject their entire home load to a time-varying rate.This presents a catch-22 for rate analysts. Creative rate design offerings are needed to overcome this tension. For example, the combination of a whole-house meter that does not differentiate by time, and a smart charger that reports TOU data for the EV consumption, can address this.

3. **The rate is promoted via a dedicated marketing effort:** To maximize enrollment, the rate should be promoted when customers are most engaged. This can be achieved at dealerships and ride-and-drive events when customers are making the EV purchasing decision, by electricians and charging station installers when customers are thinking about charging costs, and by tying enrollment to eligibility for utility-sponsored EV rebates or charging infrastructure purchases. This ensures the consumer is aware of the rate early in the process. **Typically, once the EV is purchased and the charger is installed, customer engagement is reduced and "momentum" towards the EV time-varying rate enrollment is lost.**

6) What To Do About Metering

There are many important rate design program considerations, but one of the most important is the meter. The available metering configurations influence the type of rates than can be offered to customers, the costs of enrollment, the type of administration, the ease of integration with existing billing systems, the security and reliability of charging signals, and the adaptability of the program to handle future EV technology changes. There are five basic ways to meter and bill residential customers for EV time-varying rates. The pros and cons for each are discussed in the section below and presented in Table 7.[39]

1. **Existing Meter:** This is used for a whole house rate, and leverages the existing meter.
2. **Second Meter:** This would be for an EV-only rate and requires a second service and the necessary home wiring, in addition to the customer's existing residential service.
3. **Submeter:** This would be used for an EV-only rate and would be connected to the primary meter, and may not require similar additional home wiring.
4. **EVSE Telemetry:** Utilities could leverage 1) built-in EVSE telemetry routed to the utility through the vendor/network service provider or 2) the EVSE would send data to the utility via AMI backhaul enabled by Power Line Communication (PLC) (e.g., Zigbee, GreenPHY).
5. **Load disaggregation:** Utilities would collect primary meter data and use an analytical tool to disaggregate the load and identify the portion used by the EV. This could also be accomplished with the assistance of a device, such as a meter collar.

Utility approaches to metering varied across the sample set. As new technologies providing improved capabilities emerge, those options will continue to expand. This section highlights utility approaches to metering today, the pros and cons of specific approaches, and case studies highlighting utilities that have developed innovative rate programs via their metering approach.

39 In addition to the evaluation of metering options in Table 7 and discussed throughout this section, utilities must also consider the relevant statutory and regulatory requirements applicable in their jurisdiction. Some metering configurations presented in this report may not be covered or allowed by existing statutes and regulations. For example, the Maryland Public Service Commission recently granted a temporary waiver of certain regulations governing the submetering process to the investor-owned utilities in the state for a five-year EV portfolio program. By granting the temporary waiver, the utilities can utilize customer EVSE devices as electric submeters for billing purposes without violating Code of Maryland Regulations. For more information, see Order No. 88997, "In the Matter of the Petition of the Electric Vehicle Work Group for Implementation of a Statewide Electric Vehicle Portfolio", Public Service Commission of Maryland, Case No. 9478, January 14, 2019.

A. Utility Approaches to Metering Vary

Utilities with active EV time-varying rates (see list in Appendix A) have employed a variety of approaches to metering and billing of EV charging load. Of the 64 EV rates, 43 used the primary meter (of which one used load disaggregation), 28 had a second meter, and 7 used a submeter (of which 2 were through the EVSE) as shown in Figure 24. Thirteen of the rates allowed more than one option under the same rate tariff.

It is important to note that the project team was unable to identify a correlation between the metering configuration and enrollment levels. As discussed in Table 7, challenges exist with all metering approaches, but utilities can develop creative solutions that help consumers meet their needs. For example, Braintree Electric—one of the featured case studies in this section—successfully enrolled 80% of EV customers in a whole home rate using load disaggregation to incentivize off-peak charging through a retroactive incentive payment (also known as an off-peak credit). Utilities also overcame metering limitations through effective marketing strategies.

Using a whole-house meter avoids the costs of installing a second meter or submeter, however, it requires the entire home to be on the same rate as the EV. This creates customer concerns about bill increases or potential inconvenience related to changing behavior. While there are some tools customers can use to mitigate these concerns, a preferable solution may be to use a secondary meter or submeter to separately bill the EV portion of the consumption. However, it is important to address how to recoup the equipment and installation costs for the secondary meter or submeter through cost recovery.

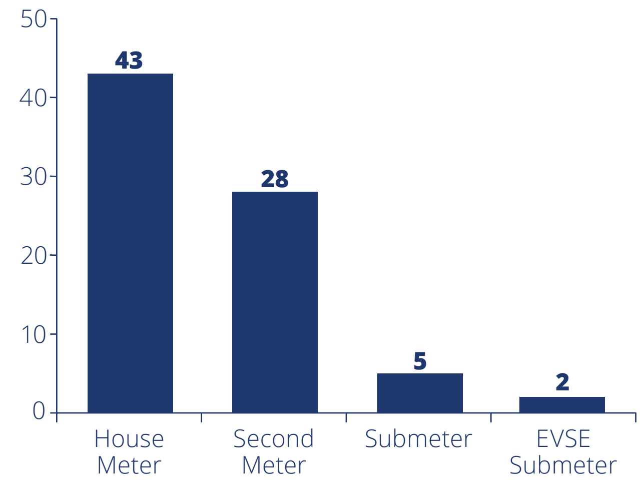
There are two options for cost recovery:

1. collecting the costs directly from the customer (this could be via a lump-sum fee or monthly charge) or
2. socializing the costs across a broader group of customers.

According to the utility survey, 50% recovered the costs directly from the EV rate customer (in a lump sum fee or a monthly charge) and the other 50% recovered from all customers.[40]

Alternatively, utilities could leverage the primary smart meter through whole-home rates or load data disaggregation techniques to provide a more accurate accounting of EV charging load. One such technique, known as non-intrusive load monitoring (NILM) has been developed to disaggregate load components based on historical data of load signatures. These techniques become considerably more accurate when load data is collected in sub-hourly intervals. An example of this is highlighted in the Braintree Electric Light Department case study.

Figure 24: Metering Configuration for EV Rate Population



Source: Smart Electric Power Alliance, 2019. N=64
Note: The authors did not identify AMI vs. non-AMI meters.

While there are potential benefits of using the telemetry in the EVSE, including lower submetering costs and customer choice, a major challenge is providing the data from an independent vendor/network service provider to the utility billing system. The integration is often costly and varies from utility to utility. Open standards will assist in lowering these costs but have not yet been implemented. The data needs to be in the proper format, and the business processes to use it have to be aligned, as well (e.g., timing of data delivery, rules for dealing with missing or invalid data, how the data file transaction occurs—i.e., how is it started, how is data receipt confirmed). Additional information about using the EVSE telemetry can be found in the Xcel Minnesota and San Diego Gas & Electric case studies in Section C.

40 Based on utility survey. N=12

Table 7: Pros and Cons of Different Metering Approaches					
	Existing Meter	**Secondary Meter**	**Submeter**	**EVSE Telemetry**	**AMI Load Disaggregation**
Ability to Meter EV Charging Separately	No—Does not separate the EVSE from rest of load	Yes	Yes	Yes—Accuracy for billing purposes depends on EVSE manufacturer	Yes—Accuracy depends on ability to identify unique kW signature of EVSE
Utility Bill Integration	Easiest to integrate	Easiest to integrate	Easier to integrate	Difficult to standardize among multiple vendors and retroactively integrate into billing system; data via AMI backhaul more accurate	Depending on the format of the disaggregated data, may not integrate
Consumer Participation Cost	No additional cost	Depending on tariff, no up-front cost to consumer, or consumer pays for the full cost	Depending on tariff, no up-front cost to consumer, or consumer pays for the full cost	No additional cost if consumer already purchased the equipment; potential additional cost for compatible EVSE	Depending on tariff, some cost for administration, third-party costs, or equipment
Volume of Eligible Customers with AMI	Highest—independent of EVSE type	Highest—independent of EVSE type	Highest—independent of EVSE type	Limited to eligible EVSE vendors	Highest—independent of EVSE type

Source: Smart Electric Power Alliance, 2019.

B. Pairing Rates with Meters: Offering Customers More Choices

Rather than focusing on identifying a system-wide metering solution, utilities and customers may be better served by a combination of rate and metering configurations. As highlighted above in Table 7, and further explained below in the utility case studies, each type of rate offering and metering configuration offers advantages and disadvantages for utility implementation and customer appeal. For example, a separately-metered EV-Only rate option may allow utilities to design a rate to convey price signals specific to customer EV usage patterns. A benefit of this option is that utilities do not have to consider other household appliances and load in the design of the rate. Likewise, customers will not be required to adjust their non-EV residential energy consumption in order to maximize savings under the rate. This flexibility could allow the utility to design a rate that appeals to EV customers with higher financial risk tolerances by offering a TOU rate with a higher peak-to-off-peak price ratio or a dynamic pricing rate.

When considering time-varying rate options, financial risk-reward trade-offs are associated with each rate that utilities consider, as not all customers will tolerate the same risk (see Figure 25). According to the Regulatory Assistance Project, "rates offering the most reward (in terms of bill savings potential) are also the most risky (in terms of exposing the customer to the volatility of wholesale electricity markets). Which rates customers select will be determined by their risk tolerance."[41]

Alternatively, a whole-house rate may offer utilities a more forward-looking approach to encourage customer off-peak consumption for not just their EV, but other energy-intensive appliances such as electric water heaters. As rate designs continue to evolve and technologies mature, utilities may find that more complex and comprehensive "smart house" rates—providing grid-integrated water

41 Regulatory Assistance Project and The Brattle Group, July 2012, *Time-Varying and Dynamic Rate Design*, https://www.raponline.org/wp-content/uploads/2016/05/rap-faruquihledikpalmer-timevaryingdynamicratedesign-2012-jul-23.pdf.

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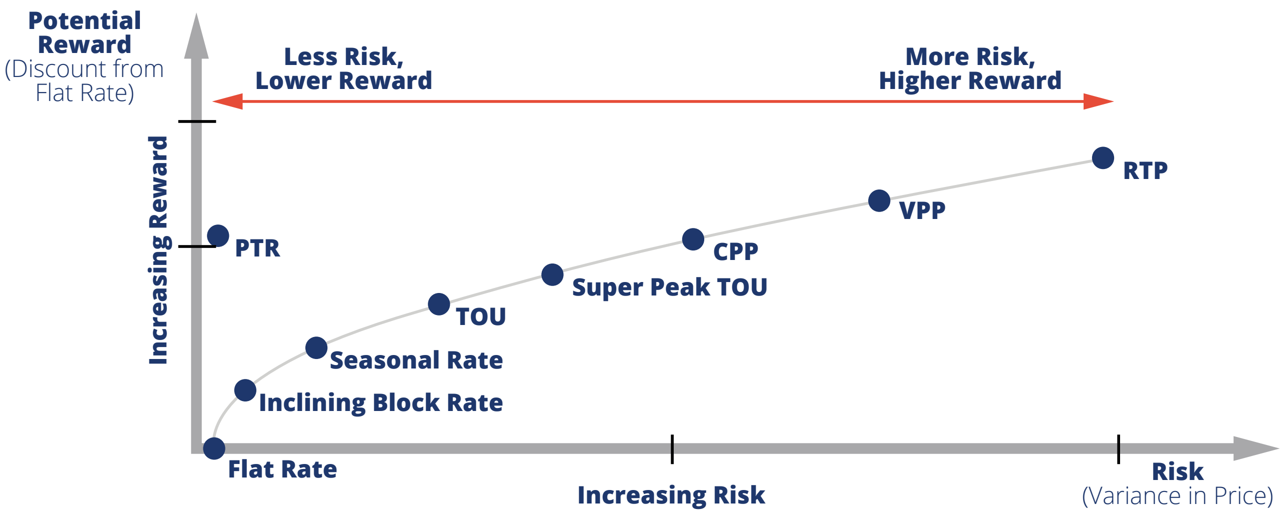
Figure 25: Conceptual Representation of the Risk-Reward Tradeoff in Time-Varying Rates



Source: The Brattle Group, 2012.[42]

heating, smart thermostats, smart laundry, and smart charging as a package, for example—offer an appealing opportunity for grid benefits and customer savings in addition to technology or appliance-specific rates.

The best metering configuration for a customer is influenced by multiple factors, such as pricing, their rate structure (e..g, TOU or a dynamic rate), applicable enrollment or equipment fees, and the hours designated as peak and off-peak time periods. In addition to a customer's financial risk tolerance, utilities also need to consider important behavioral considerations, such as work schedules and the flexibility to shift electricity consumption to designated off-peak hours for particular appliances or for the entire home. These factors interact, and can represent an array of different EV customer "types" (Figure 26). Examples could include:

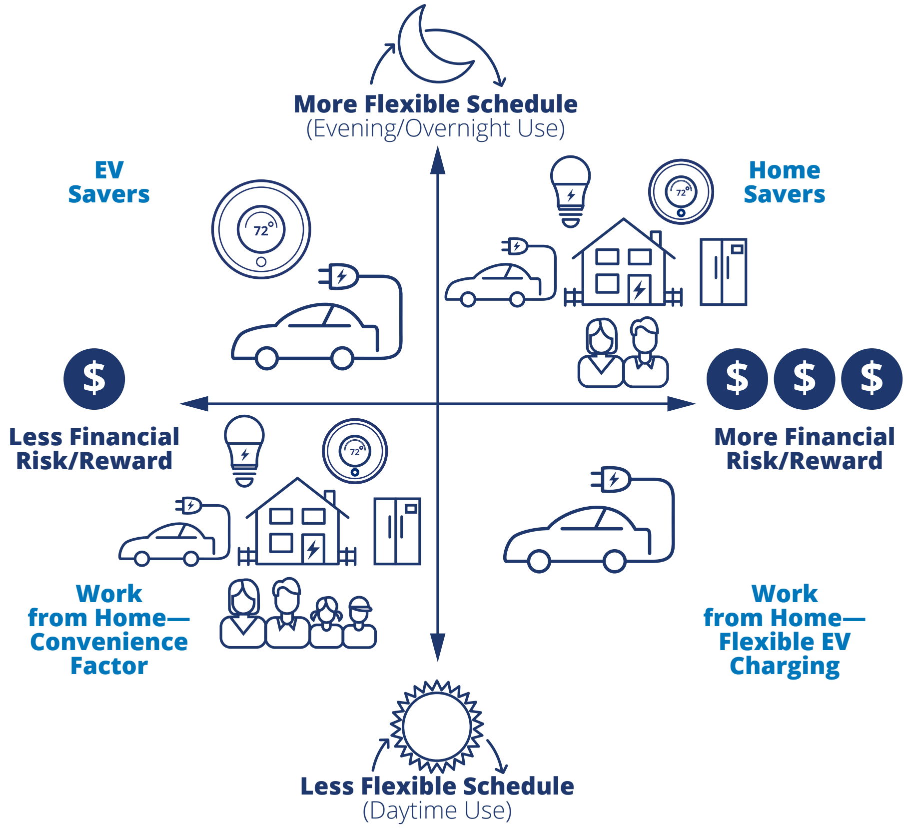
- **"Home Savers"—Outside the house during the day:** Households with more flexibility to shift entire household load to the off-peak hours and a strong interest in savings (Potential Solution: Whole House time-varying rate).
- **"EV Savers"—Outside the house during the day:** Households with flexibility to shift some load to the off-peak hours but less interested in savings, and more concerned with avoiding higher prices for entire household consumption (Potential Solution: Separately-metered time-varying rate for EV Only + other select household appliances).
- **"Work from Home"—Flexible EV charging:** Households with less flexibility to shift entire household load to avoid on-peak usage, but still have a strong interest in savings (Potential Solution: Separately-metered time-varying rate for EV only).
- **"Work from Home"—Convenience factor:** Households with less flexibility to shift entire household load to the off-peak hours and are more concerned with avoiding higher prices for on-peak usage (Potential Solution: Participate in a retroactive bill credit program.

As previously highlighted, a number of utilities offer their customers multiple rate and metering configurations for their home charging. Of the rates surveyed, 13 allow for more than one metering configuration under the same rate schedule. The most common pairing is a Whole House TOU rate (serviced on a single home meter) and a separately-metered EV-only TOU rate.

In addition eliminating barriers to participation, such as up-front costs or fees for customers, utilities can encourage higher enrollment by offering customers different rate and metering configuration options that appeal to a wider group of customer types and preferences across their service territories.

42 Regulatory Assistance Project and The Brattle Group, July 2012, *Time-Varying and Dynamic Rate Design*, https://www.raponline.org/wp-content/uploads/2016/05/rap-faruquihledikpalmer-timevaryingdynamicratedesign-2012-jul-23.pdf.

Figure 26: Illustrative EV Customer "Types"



Source: Smart Electric Power Alliance, 2019.

C. Utility Metering Case Studies

It is worthwhile to explore options to 1) integrate EV charging data into a utility billing system at the lowest cost, 2) increase convenience and satisfaction for the customer, and 3) ensure accuracy, reliability, and security. The following case studies feature innovative utility programs that implement different metering methods, specifically for:

1. Submeter (Indiana Michigan Power)
2. Submeter—EVSE telemetry (San Diego Gas & Electric)
3. Submeter—EVSE telemetry (Xcel Energy Minnesota)
4. Second meter—subscription rate (Austin Energy)
5. AMI load disaggregation (Braintree Electric Light Department)

The case studies discuss these integration opportunities, and highlight rate design and program implementation opportunities. These were among the most innovative programs identified in the survey.

1) Submeter: Indiana Michigan Power Leveraging Smart Meter Networks

Indiana Michigan Power—a subsidiary of American Electric Power (AEP)—found that EV customers want to know two things from their utility company: 1) how much it costs to charge their vehicles, and 2) if the utility offers incentives for charging. According to AEP, many EV owners either receive charging hardware with their vehicle or purchase directly from a retailer, and therefore may not need or want utility program-specific charging hardware.

One of the first decisions customers make after buying an EV is how they charge at home. Some customers are content with level 1 charging, others use the level 2 cordset chargers that come with their car (e.g., Tesla, Nissan, Audi) and install 240 volt service, while some others purchase a more sophisticated networked level 2 charging station. Regardless of the charging hardware chosen, EV owners can easily schedule charging through the car's in-dash screen, automaker apps, third-party apps, and even through digital voice assistants.

Given this ease of scheduling charging, customers will typically schedule their charging on nights and weekends if given a price signal. AEP has found TOU pricing to be very effective for shifting EV load to off-peak times.

AEP has identified a problem with offering only whole-house TOU rates in that they often require other customer behavioral changes related to heating and cooling that can hinder customer adoption. Instead, allowing customers to meter only their EV charging with an EV-only TOU rate can remove the customer apprehension around whole-house TOU rates.

AEP evaluated options for metering EV-only TOU rates:

- Via networked charging stations
- Through a separate utility service connection
- Using an EV-specific AMI submeter

AEP evaluated each option, considering cost, accuracy, security, communication reliability, billing integration, and other factors.

For the option of metering through network charging stations, they found challenges with:

- The reliability and security of customer Wi-Fi when communicating with the chargers.
- The difficulty of integrating charger network data with their existing utility CIS/billing system, which can be expensive to modify. Receiving usage files from a variety of network operators would require manual billing. This can result in mismatched time stamps, missing data due to loss of Wi-Fi connection, and significant opportunity for errors.
- The potential expense of accessing managed charging networks, including unpredictable network fees with uncertain future increases.
- Requiring customers to buy a utility-specified charger and utilize the associated network as a condition of program participation, which the customer may not need or want.
- The ability to adapt to future changes as the EV market evolves. OEMs are increasingly including level 2 cordset chargers as standard equipment with their vehicles, so the utility programs need to accommodate this change.

When considering establishing a separate utility service, AEP found that other utility programs incurred high administrative and equipment costs. The additional service increased costs for customers by requiring additional electrical hardware, incurring a second 'customer account charge', and duplicating other costs. They concluded this wasn't a cost-effective option for their customers.

When evaluating the use of an EV-specific AMI submeter, AEP found many benefits:

- The meter meets the regulatory accuracy requirements for billing tariffs.
- The security of the meter hardware and the interface with AEP's systems is inherent.
- Use of the existing AMI RF communications network is reliable.
- Integration with CIS and billing systems doesn't require significant IT investment or expensive manual billing.
- The purchase price of the meters is reasonable under existing utility-scale purchase volumes.
- The solution avoided exposure to unknowable future charger network access fees.
- AEP could potentially leverage the basic on/off control functionality of the AMI submeters for active-managed charging in the future, if that is needed.

For the customer, this solution avoids the need to completely adjust their behavior to accommodate a whole-house TOU-rate, or to purchase a utility-specified charger. It also allows customers to choose how they wish to control their vehicle charging. AEP found this approach to be the simplest, most convenient, adaptable, and lowest cost option.

2) Submeter—EVSE Telemetry: San Diego Gas & Electric (SDG&E) Power Your Drive

SDG&E developed the Power Your Drive pilot program aimed at workplace and multi-unit dwelling property owners to encourage increased EV adoption, especially in communities of concern. Once the chargers are deployed, EV drivers at the sites can sign up and gain access to over 3,000 charging stations at over 250 locations. The program has a special pricing plan that offers lower prices during grid-friendly times such as times of high renewable penetration or low grid congestion. Customers can set a maximum price to charge their EV. When the hourly price exceeds the maximum price, charging stops.

In the development of this rate, SDG&E tackled challenges of both diversity between circuit and system peaks, as well as diversity of peaks and load shapes across different circuits, while ensuring all customers are treated equitably. Because the program targeted specific locations, locational pricing was a concern for regulators. If a utility charged solely based on load, it could create inequity from one location to another. To address this, SDG&E used a critical peak price (CPP) concept and incorporated circuit level pricing. By applying the same price to every circuit, they resolved the issue of equitable pricing for customers across locations.

Each location has the exact same pricing structure, but at different times.

When examining time-varying rate options, Cyndee Fang, manager of energy research and analysis at SDG&E, recommends utilities ensure that the options they provide customers are purposeful, which may mean a limited number of choices but making the choices meaningful for the customer. Too many rate offerings can be confusing and too few fail to address specific customer needs. A static time-of-use rate is best for customers who are able to shift usage out of defined high cost hours, whereas dynamic rates help customers who are more responsive to tap into additional savings.

Hannon Rasool, the clean transportation business development manager at SDG&E, stated that, "submetered[43] EV-only rates allow for more complexity in the rate design as they require fewer human behavioral adjustments around the home." Given the potential size and flexibility of EV loads, an EV-only rate provides the opportunity to create a rate that is flexible and forward looking. "If you can get the design out there, people are able to get the technology to match the rate design," said Fang.

Rasool added that utilities planning to develop an EV-only time-varying rate should be focused on incorporating the EV load to the grid in a manner that doesn't increase costs. "Proper rate design can help save money and achieve the environmental benefits we all want to see. Utilities planning an EV program should look into how they can incorporate the additional load into the grid and that is where actionable rate signals really matter," said Rasool.

A significant opportunity provided by SDG&E's rate is that despite its complexity, it is a more dynamic rate offering and opens up more low-cost hours for flexible loads such as EV charging. This makes it meaningful for customers, and gives them choices. "Utilities have to be mindful about options put out there and ensure they bring value for customers," said Fang.

3) Submeter—EVSE Telemetry: Xcel Energy Minnesota Residential EV Service Pilot

Xcel Energy Minnesota launched a Residential EV Service Pilot in 2018 offering an EV TOU rate that leveraged networked Level 2 charging equipment to lower the initial cost to enroll.[44] The pilot was designed to test the potential for cost savings and improved customer experiences through a combination of new equipment deployment and off-peak rate design. By leveraging the telemetry capabilities of the EVSE, utilities could use charger equipment to provide billing-quality data. The program avoided the need for customers to pay for the installation and cost of a second meter. In addition, the pilot improved the customer experience while maintaining a safe and reliable electricity service.

The pilot was capped at 100 participants with average savings of the cost of EVSE and metering installation of $2,196 per customer compared to the costs associated with equipment and installation for the separately metered option.[45] Actual savings were dependent on the availability of an existing 240 volt dedicated circuit needed for the Level 2 charger as well as proximity to the garage, panel location, and circuit pathway.

Xcel Energy offered customers chargers from two EVSE manufacturers, ChargePoint and Enel X. Xcel Energy found that while the data provided by the charging equipment was sufficiently accurate, formatting the data so it could be received by the company and successfully uploaded to the billing system required significant collaboration with the vendors. Moving forward, Xcel Energy plans to explore ways in which it can improve integration and operations between its systems and charging equipment options.

The pilot resulted in a 96% of the charging load was off-peak. Based on an assumption of 350 kWh of usage per month and the current level of off-peak charging, enrolled customers would save $9.76 per month or $117.12 per year on the TOU rate.

The pilot provided a positive turn-key customer experience for electric vehicle charging in the home, with customer satisfaction scoring 87% for enrollment and 95% for charging equipment installation. From the 63 survey responses, Xcel Energy also identified areas for improvement, including explaining rate pricing, communicating with customers, and providing information about the charger options. While customers understood and recognized the pricing signal (in that charging their EV during off-peak hours is cheaper and provides benefits), they were confused about the pricing, components of the rate and on-bill presentation, as well as the expected

43 In PYD, SDG&E used data collected from submeters in the EV chargers for billing after qualifying the submeters through a rigorous testing process. Two chargers were accepted, from Siemens and ChargePoint, meeting the testing criteria of +/- 1.0%.

44 Note: This pilot was intended for customers who wanted a new EVSE at their home. Xcel has other rate options, such as a whole home TOU, for customers that prefer level one charging, a non-networked charger, or other options. Additional information about the program is available in the *Residential Electric Vehicle Charging Tariff Docket* No. E002/ M-15-111 and E002/ M-17-817, 2019.

45 The savings are measured by asking electricians to provide the customer with (at least) two estimates for wiring their home—one being a separate service/meter, one being a dedicated circuit behind the customers main panel/existing meter. Xcel identified the difference between these estimates as the savings vs the existing separately metered rate.

fuel savings and payback period for their investment. Xcel Energy plans to leverage digital tools and more comprehensive energy consumption data to provide customers with better insights into the benefits.

Seventy-three percent of participants in the EV Service Pilot preferred to pay for the charging equipment and installation through a bundled monthly charge, instead of the prepayment option, indicating that customers prefer to reduce upfront costs and simplify participation. Xcel Energy plans to adjust the tariff as needed and experiment with subscription models.

4) Second Meters: Austin Energy EV360 Subscription-based Rate

In 2015, Austin Energy developed three new pilot rates with the goal of offering customers more rate options. Along with an EV-only subscription rate, a prepayment rate and a whole-home Time-of-Use rate were piloted. The subscription, titled EV360, offers customers with a capacity demand of less than 10 kW the ability to use unlimited off-peak (7pm-2pm weekdays, anytime during weekends) kWh's for EV charging for a fixed monthly fee of $30.[46] Customers with demand over 10 kW have a fixed monthly fee of $50. Customers are able to charge on-peak, but will incur a bill adder of $0.14/kWh during the winter and $0.40/kWh during the summer.

The subscription coupled TOU-like hours with a fixed charge to give EV customers a predictable bill. To date, the rate has resulted in 99% of participants using off-peak electricity. However, Austin Energy has yet to determine how much it has changed charging behavior beyond initial survey data.

Lindsey McDougall, the Program Manager for the EV360 program, published a report in September 2019 which highlighted key takeaways and lessons learned from the pilot program.[47] A key element of the pilot's success was educating customers. Participation required a large investment by the customer, as they had to install both a conduit and meter socket for the meter, obtain a permit, and hire an electrician. This meant the pilot was limited in reach, with those interested in participating being well-educated and eager to participate. Pilot participation required significant guidance from the utility. Austin Energy worked closely with EVSE installers to inform them about the program and created an "Installers tab" on their website.

As EV360 was a small pilot with 100 participants, management and administration of the program was performed by one person—Lindsey McDougall. While manageable for a small pilot, if Austin Energy decides to offer the rate to all customers, additional staff would be required, as well as training the call center to handle customer inquiries.

Reflecting on the pilot, McDougall noted that subscription rates will be important to EV drivers and utilities. "EV drivers charge off-peak for green initiatives and cost savings and utilities will be expected to have the same values. Consequently, there will be huge demand for utilities to not penalize customers for having an EV, but instead having rate structures that encourage conservation where possible."

In addition to EV-only rates, McDougall also noted that subscription structures could apply to other scenarios, for example the whole home. "Especially with distributed energy service providers, utilities will see a more dynamic relationship between energy resources and consumption. There will become a two-way channel between the utility and the customer."

5) AMI Load Disaggregation: Braintree Electric Light Department (BELD), Bring Your Own Charger®

Advanced metering infrastructure (AMI) is an integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers. Typically gathering energy consumption data in 15-minute intervals, AMI meters can generate vast amounts of data, with the exact data varying based on utility and system.

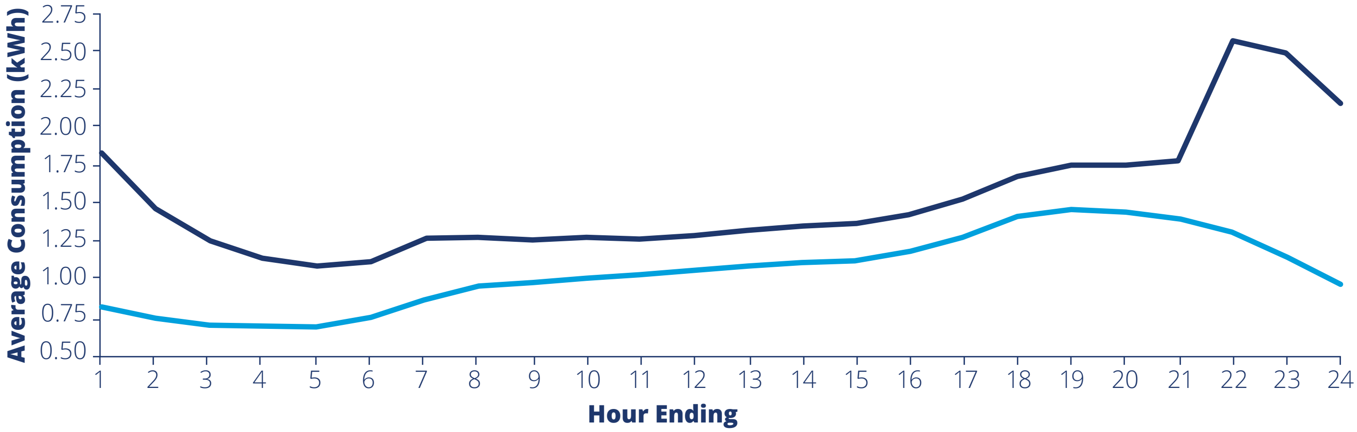
BELD launched Sagewell's Bring Your Own Charger® (BYOC) electric vehicle load management program in 2017, and has approximately 80% of known EVs in their service area under load management. The BYOC program does not require any load control hardware because it utilizes AMI meter data to verify off-peak charging compliance.

BELD began residential EV load management three years ago, initially focusing on load control through EV smart chargers. However, they quickly identified difficulties in getting a significant volume of smart chargers installed and high program costs as key obstacles and transitioned to Sagewell's non-hardware-based BYOC solution to

46 Additional details about the rate design are on page 7: Austin Energy, EV360 Whitepaper, *Austin Energy's Residential "Off Peak" Electric Vehicle Charging Subscription Pilot: Approach, Findings, and Utility Toolkit*, https://austinenergy.com/wcm/connect/b216f45c-0dea-4184-9e3a-6f5178dd5112/ResourcePlanningStudies-EV-Whitepaper.pdf?MOD=AJPERES&CVID=mQosOPJ.

47 See Austin Energy, EV360 Whitepaper, *Austin Energy's Residential "Off Peak" Electric Vehicle Charging Subscription Pilot: Approach, Findings, and Utility Toolkit*, https://austinenergy.com/wcm/connect/b216f45c-0dea-4184-9e3a-6f5178dd5112/ResourcePlanningStudies-EV-Whitepaper.pdf?MOD=AJPERES&CVID=mQosOPJ.

Figure 27: Identifying the Load Profile from Average Enrolled EV Home Compared to Average Single Family Home in Braintree



Source: Sagewell Bring Your Own Charger (BYOC), 2019.

monitor EV charging using whole-home smart meter load disaggregation (Figure 27). Through the program, BELD has tracked customer charging of over 12,000 EV charging days and verified over 95% off-peak charging compliance.

EV owners who agree to program their vehicles to charge during off-peak hours are given a bill credit as an incentive. If on-peak charging is identified from the AMI meter data, customers were reminded they could lose the incentive for the month. This daily tracking and accountability drove significantly higher rates of successful off-peak charging than do TOU rates, which achieve 70% to 80% of EV charging during off-peak hours, based on Sagewell's AMI meter tracking data.

BELD found that eliminating load-control hardware caused a higher percentage of EV owners in its service territory to enroll in the program. The average customer enrollment time is only 7 minutes via smartphone. Sagewell provides support and program oversight to help customers as they begin enrollment. BELD also found that enrolling customers early in their EV ownership led to maximum enrollment as enrollment rates decreased the longer a customer owned an EV. BELD has used Sagewell's EVFinder algorithm daily to find new EVs in utility smart meter data and to direct EV program marketing messages that included BYOC information to those customers who recently acquired an EV.

BELD's analysis of smart meter data also highlighted that utilities should carefully analyze their TOU rates because many may be discounting their regular residential rates too much and giving up more in margins than the peak load reduction justifies. The BYOC program produced significantly higher program participation and larger peak load reduction at a lower cost than TOU rates. Sagewell encourages utilities to carefully analyze their EV load management options and to use their AMI data to find the peak load reduction potential for customers rather than using modeled results or data from other utilities. For example, differences in weather, miles driven and utility coincident peak times between different regions make it challenging to compare results between different EV load management programs and highlights the importance of using local AMI meter data for the analysis.

7) Conclusion

Time-varying rates are a valuable tool for utilities to manage system costs by influencing residential EV charging behavior. Specifically, the quantitative analysis described in this study shows that EV time-varying rates effectively incentivize off-peak charging, and that customers are interested in using them. Enticing the maximum number of EV customers to enroll in these rates is essential to ensuring that EV charging load is managed effectively. Designing rates that encourage off-peak charging, save customers money, require limited up-front fees, and that

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are easily available to EV customers leads to the highest customer enrollments.

This section includes recommendations for utilities as they consider options for EV time-varying rates, and provides next steps for other research topics, as we continue to refine our knowledge about load management strategies.

A. Recommendations

Utilities can take advantage of early opportunities to improve EV-grid integration through time-varying rates. Recommendations compiled from the survey results and utility interviews include:

1. Minimize the up-front costs for customer enrollment wherever possible. Utility costs may include metering equipment (and in some cases EVSE), installation, and in-house utility overhead such as IT setup, marketing, etc. Determining which costs the customer bears, the manner in which they are collected (e.g., bundled monthly charge versus a prepayment option), as well as the recovery mechanisms for costs not recovered directly from participants are critical considerations for utilities and regulators.
2. Make the price differential between 'on-peak' and 'off-peak' significantly large to incentivize participation, but not so large that it deters customers from enrolling. Offering multiple rate options with different designs allows utilities to appeal to and engage more customer types and preferences.
3. Where possible, incorporate an "opt out" rather than passive "opt in" elective—especially for programs containing a rebate or incentive for a charger or vehicle purchase.
4. Make the time-varying rate options for consumers meaningful, with substantive differences in the rate structures rather than offering customers several rates that have only slight variations. Provide tools and information to help customers make a rate choice that works best for them.
5. Consider innovative approaches to rates and incentives, such as dynamic rates, off-peak credits, subscription rates, and load disaggregation with retroactive incentives.
6. Ensure adequate marketing funding to promote the rate to customers. Use multiple marketing channels to amplify the message. Target rate marketing among known or likely EV drivers.
7. Build a long-term strategy to transition from passive managed charging to active managed charging, considering the time it may take to introduce and get regulatory approval for new rates and programs.
8. Work with EVSE providers to deliver unified open standards that could lower the cost of integrating networked EV charger telemetry.

B. Future Research

While this report provides valuable new insight into EV time-varying rates, a number of questions remain. These include elements of rate design, evaluation, measurement, and verification (EM&V) of rate effectiveness, lower-cost alternatives to collecting charging data, how to measure the key performance indicators (KPI) of marketing efforts, the appropriateness of ratebasing program costs, and more, as outlined below.

Active Load Management

- What is the time horizon for active load management offered by utilities and private vendors? What is the value of active load management and what are the use cases?

Rate Design

- Which customer segments prefer a separately metered EV-only rate to a whole-home rate? What portion of the customer base—enough to justify utilities offering customers both options?
- How can utilities design rates to promote efficient utilization of lower-cost and clean generation resources?
- Will customers shift load to the off-peak period if it occurs in the middle of the day (e.g., when there is excess solar PV output)?
- Do customers respond differently to peak/off-peak pricing than to rate discounts, monthly incentives, or bonuses for charging at night?

- Nearly all of the EV Time-Varying Rates reviewed in this report are TOU programs. Should utilities explore other time-varying rate options for EV charging and would some residential EV customers be better off under one of these alternatives versus a TOU rate?
- Should time-varying rates be required for participants in ratepayer-funded EV home charging programs to ensure that all customers benefit from large-scale shifts in EV charging load to off-peak periods?

Rate Performance

- Is time-varying EV pricing effective at encouraging EV adoption, or is it primarily for encouraging off-peak charging once the EV has been purchased?
- How will these rates impact charging behavior—especially among later adopters of EV technology?
- How will utilities evaluate, measure, and verify the effectiveness of EV rates—particularly utilities transitioning from a pilot to a rate of general application?
- How do you measure the KPI of marketing expenditures to increase the number of consumers on a rate and/or who purchase an EV as a result of the rate?

Cost Recovery

- Should secondary or submetering costs be recovered from participants (which could be a significant deterrent to participating) or will the rate lead to off-peak charging and benefit all customers, thereby justifying recovery of the meter cost from a broader group of customers? Should costs be recovered differently for "early adopters" versus "late adopters" of EV technology? How should the costs associated with EV rate and program marketing, IT set up costs, and other overhead be recovered?

Technology Considerations

- Will additional incentives encourage higher enrollment and more off-peak charging?
- Can customers enrolled in one demand management program, such as EV charging, be motivated to join other programs, such as smart thermostats or grid-integrated water heating?
- How can new tools help increase enrollment, such as showing customers their average charging patterns in monthly bills, compared to a different charging pattern or a different rate?

Appendix A: List of Available Residential EV Time-Varying Rates

The list of available residential EV time-varying rates was compiled using research from SEPA The Brattle Group, OpenEI, and other online resources. This list was updated through September 2019 and includes 64 rates from 50 utilities that were open for enrollment at the time they were collected. This list does not include expired or grandfathered rates.

Table 8: Available Residential EV Time-Varying Rates, September 2019

	Utility Name	Rate Name	Rate Type
1	Alabama Power Company	PEV Rate Rider	Time-of-Use
2	Alaska Electric Light and Power Co.	Off-Peak Electric Vehicle Charging	Time-of-Use
3	ALLETE (Minnesota Power)	EV TOU Rate	Time-of-Use
4	Anaheim Public Utilities	Developmental Schedule D-EV Rate (Developmental Domestic Electric Vehicles)	Time-of-Use
5	Austin Energy	EV360	Subscription
6	Baltimore Gas and Electric	Schedule EV	Time-of-Use
7	Belmont Light	Bring Your Own Charger	Off-Peak Credit
8	Berkeley Electric Coop Inc.	Off-Peak EV Rate	Time-of-Use
9	Braintree Electric Light Department	Bring Your Own Charger Program	Off-Peak Credit
10	City of Burbank Water and Power	Optional Time-of-Use Rates for Electric Vehicle Owners	Time-of-Use
11	Coastal EMC	TOU-PEV-1	Time-of-Use
12	CobbEMC	NiteFlex	Time-of-Use
13	Concord Municipal Light Plant	Rate R-1	Time-of-Use
14	Concord Municipal Light Plant	EV Miles Program	Off-Peak Credit
15	Consolidated Edison Company	Special Provision E of SC1 Rate III	Time-of-Use
16	Consolidated Edison Company	Special Provision F of SC1 Rate III	Time-of-Use
17	Consumers Energy Co.	REV-1	Time-of-Use
18	Consumers Energy Co.	REV-2	Time-of-Use
19	Dakota Electric Cooperative	Schedule EV-1 Pilot—Residential Electric Vehicle Service	Time-of-Use

Table 8: Available Residential EV Time-Varying Rates, September 2019

	Utility Name	Rate Name	Rate Type
20	Delmarva Power & Light	R-PIV	Time-of-Use
21	DTE	D1.9 EV Time-of-Use	Time-of-Use
22	Evergy	Residential Electric Vehicle Rate	Time-of-Use
23	Georgia Power Company	Schedule TOU-PEV-6—Plug-in Electric Vehicle	Time-of-Use
24	Gulf Power Co.	Rate Schedule RSVP Residential Service Variable Pricing	Time-of-Use
25	Hawaii Electric Light Company	Schedule TOU-RI	Time-of-Use
26	Hawaiian Electric Company	Schedule TOU-RI	Time-of-Use
27	Indiana Michigan Power Company	Tariff RS-PEV	Time-of-Use
28	Indianapolis Power & Light Company	IPL Response: Rate EVX	Time-of-Use
29	Jackson EMC	Residential Plug-in Electric Vehicle Rate (APEV-19)	Time-of-Use
30	Los Angeles Department of Water and Power	EV TOU	Time-of-Use
31	Madison Gas & Electric	Shift & Save	Time-of-Use
32	Maui Electric Company	TOU EV	Time-of-Use
33	New Hampshire Electric Cooperative	EV Time-of-Use Rate	Time-of-Use
34	Norwood Light Department	Bring Your Own Charger Program	Off-Peak Credit
35	NV Energy	OD-REVRR-TOU	Time-of-Use
36	NV Energy	ODM-1-TOU REVRR	Time-of-Use
37	NV Energy	ORS-TOU REVRR	Time-of-Use
38	NV Energy	ORM-TOU RMEVRR	Time-of-Use
39	Orange and Rockland Utilities	O&R SC19	Time-of-Use
40	Otter Tail Power Company	Off-Peak EV	Time-of-Use
41	Pacific Gas & Electric	EV-2A; Electric Schedule EV—Rate A	Time-of-Use
42	Pacific Gas & Electric	EV-B; Electric Schedule EV—Rate B	Time-of-Use
43	Pacific Power (PacifiCorp)	Schedule 5—Separately Metered Electric Vehicle Service For Residential Consumer	Time-of-Use
44	Pepco Holdings, Inc.	Whole House EV TOU	Time-of-Use

Residential Electric Vehicle Rates That Work

Table 8: Available Residential EV Time-Varying Rates, September 2019

	Utility Name	Rate Name	Rate Type
45	Piedmont Electric Membership Corporation	Schedule R/SGS-TOD-E-PEV	Time-of-Use
46	Rocky Mountain Power (PacifiCorp)	Schedule 2E—Residential Service—Electric Vehicle Time-of-Use Option—Temporary—Rate Option 1	Time-of-Use
47	Rocky Mountain Power (PacifiCorp)	Schedule 2E—Residential Service—Electric Vehicle Time-of-Use Option—Temporary—Rate Option 2	Time-of-Use
48	Sacramento Municipal Utility District	Schedule R-TOD, rate category RT01	Time-of-Use
49	Salt River Project	E-29 Residential Electric Vehicle Price Plan	Time-of-Use
50	San Diego Gas & Electric	EV TOU 2	Time-of-Use
51	San Diego Gas & Electric	EV TOU 5	Time-of-Use
52	San Diego Gas & Electric	EV TOU	Time-of-Use
53	San Francisco Public Utilities Commission	Schedule REV-1	Time-of-Use
54	Sawnee EMC	Schedule PEV-7	Time-of-Use
55	Southern California Edison Co.	TOU-D-PRIME	Time-of-Use
56	Virginia Electric & Power Co.	Schedule EV	Time-of-Use
57	Virginia Electric & Power Co.	Schedule 1EV	Time-of-Use
58	Wake Electric Membership Corporation	EV Rate	Time-of-Use
59	Wake Electric Membership Corporation	EV TOU	Time-of-Use
60	Wellesley Municipal Light Plant	Bring Your Own Charger Program	Off-Peak Credit
61	Wright-Hennepin Cooperative Electric Association	EV TOU Rate	Time-of-Use
62	Xcel Energy MN	Residential Electric Vehicle Pilot Service Rate Code A80	Time-of-Use
63	Xcel Energy MN	Residential Electric Vehicle Pilot Service Rate Code A81	Time-of-Use
64	Xcel Energy MN	Residential Electric Vehicle Service Rate Code A08	Time-of-Use

Source: Smart Electric Power Alliance, 2019. Updated through September 30, 2019.

Smart Electric Power Alliance

Appendix B: Recommended Reading

- Baltimore Gas & Electric, 2018, *BGE Electric Vehicle Off Peak Charging Pilot*, Docket 9261: In The Matter of the Investigation Into the Regulatory Treatment of Providers of Electric Vehicle Charging Stations and Related Services.
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Appendix C: Time-Varying Rate Definitions

For the purposes of this report, time-varying rates are grouped into seven categories: Time-of-Use (TOU), Subscription Rates, Off-Peak Credits, Real Time Pricing (RTP), Variable Peak Pricing (VPP), Critical Peak Pricing (CPP), and Critical Peak Rebates (CPR).[48]

These rates are illustrated in Figure 28.[49]

- **Time-of-Use (TOU)** rates typically have two or more price intervals (e.g., peak, off-peak, super-off-peak) that differ based on levels of demand observed throughout the day. Sometimes these prices vary by season, but generally speaking both the prices and the designated price interval hours for each tier remain constant from day to day.
- **Subscription Rates** allow customers to pay a fixed monthly fee for electricity and other utility-provided services in exchange for unlimited charging during certain hours of the day or days of the week. Customers would subscribe to a plan which meets their specific needs, varying from "economy" packages which give the utility some ability to control their load at restricted and pre-published times to help meet grid needs, to high-priced packages with long-term subscriptions and access to new technologies without upfront costs.
- **Off-Peak Credits** can take the form of a fixed or variable incentive provided as a rebate or a bill credit in exchange for restricting consumption to designated hours of the day or days of the week.

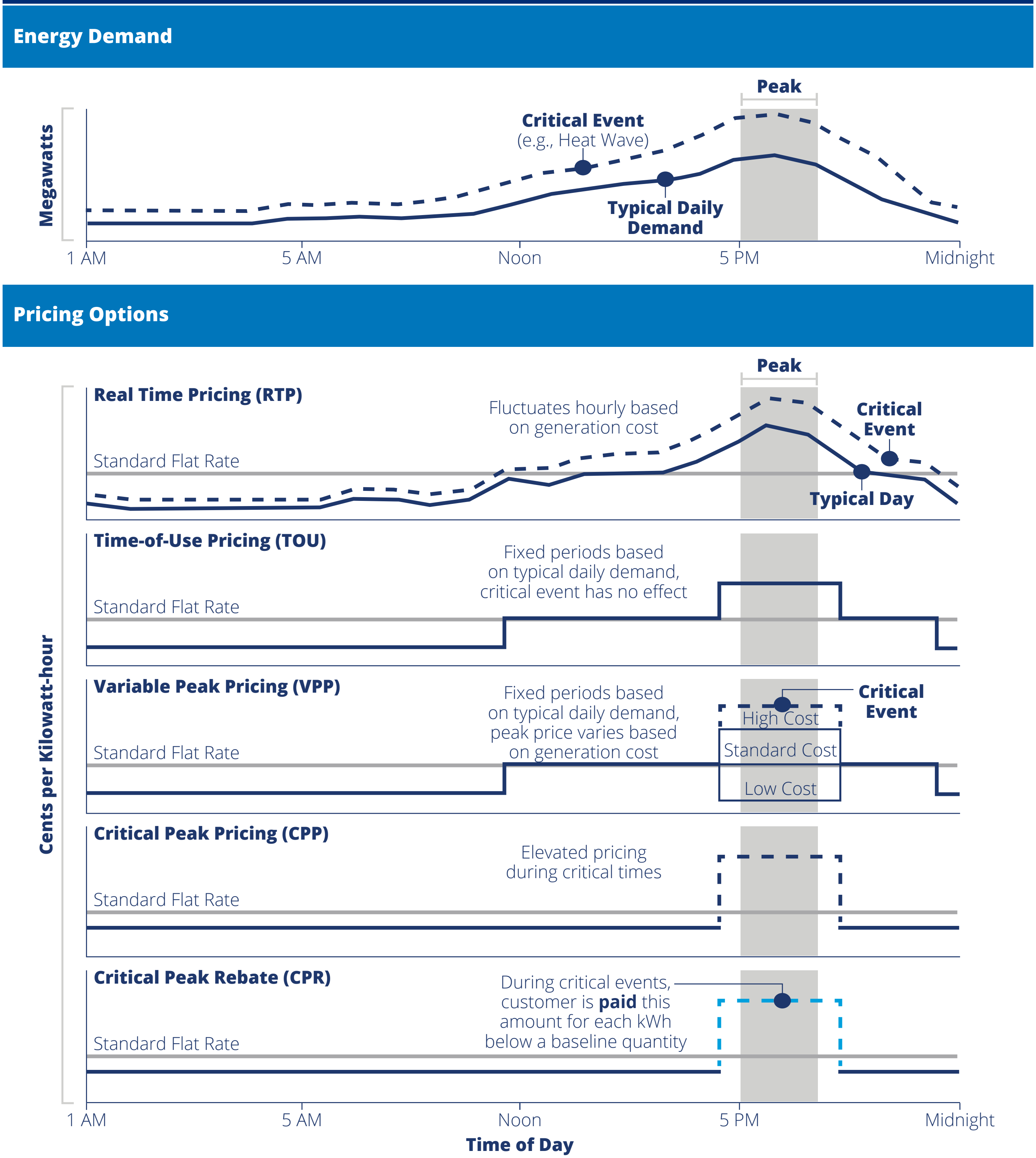
Dynamic Rates (time periods and prices vary based on system conditions and power cost):

- **Real Time Pricing (RTP)** is the most complex time-varying rate. Variable, hourly prices are determined either by day-ahead market prices in order to allow the customer to be notified with time to alter consumption decisions, or real-time spot market prices.
- **Variable Peak Pricing (VPP)** is a hybrid of TOU and RTP, with price intervals (e.g., peak, off-peak) that are constant like a TOU rate but allow for the price charged during the peak tier to differ day to day. The peak price charged varies from day to day either based on market prices or a set of predetermined levels, to reflect system conditions and costs.
- **Critical Peak Pricing (CPP)** has a higher rate at designated peak demand events (also called "critical events") on a limited number of days during the year to reflect the higher system costs during these hours. The customer can avoid paying high prices by reducing electricity use during these periods of high demand (which may only occur up to a predetermined number of times per year) and benefit from a lower price for non-event hours relative to the flat rate.This pricing provides a strong incentive for customers to reduce consumption during peak hours of critical event days, but provides no incentive to reduce use on non-event days or hours.
- **Critical Peak Rebate (CPR)**, also called Peak Time Rebate (PTR), is the inverse of CPP. Utilities pay customers a rebate for each kWh of electricity they reduce during peak hours of peak demand events. Similar to CPP, this pricing incentivizes a reduction in use during even days, but does not provide an incentive for customers to reduce use on non-event days or hours.

48 Definitions adapted from: Environmental Defense Fund, 2015, *A Primer On Time-Variant Electricity Pricing*, https://www.edf.org/sites/default/files/a_primer_on_time-variant_pricing.pdf . Subscription Rates and Off-Peak Credits are not discussed in the EDF primer.

49 Ibid.

Figure 28: Time-Varying Rate Options



Source: Environmental Defense Fund, 2015 with edits by the Smart Electric Power Alliance.[50]

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50 Environmental Defense Fund, 2015, *A Primer On Time-Variant Electricity Pricing*, https://www.edf.org/sites/default/files/a_primer_on_time-variant_pricing.pdf

Smart Electric Power Alliance

1220 19TH STREET NW, SUITE 800,
WASHINGTON, DC 20036-2405
202-857-0898

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1214

In the Matter of:	)
Application of Duke Energy Carolinas,	)
LLC for Adjustment of Rates and	)
Charges Applicable to Electric Service	)
in North Carolina	)

DIRECT TESTIMONY OF
JUSTIN R. BARNES
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT JRB-5

I/A

FROM GAS TO GRID

BUILDING CHARGING INFRASTRUCTURE TO POWER ELECTRIC VEHICLE DEMAND

BY GARRETT FITZGERALD, CHRIS NELDER

MOBILITY TRANSFORMATION

AUTHORS & ACKNOWLEDGMENTS

AUTHORS

Garrett Fitzgerald and Chris Nelder

** Authors listed alphabetically. All authors from Rocky Mountain Institute unless otherwise noted.*

CONTACTS

Chris Nelder (cnelder@rmi.org)
Garrett Fitzgerald (gfitzgerald@rmi.org)

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ABOUT US

ABOUT ROCKY MOUNTAIN INSTITUTE

Rocky Mountain Institute (RMI)—an independent nonprofit founded in 1982—transforms global energy use to create a clean, prosperous, and secure low-carbon future. It engages businesses, communities, institutions, and entrepreneurs to accelerate the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables. RMI has offices in Basalt and Boulder, Colorado; New York City; Washington, D.C.; and Beijing.

ABOUT MOBILITY TRANSFORMATION

Rocky Mountain Institute's Mobility Transformation program brings together public and private stakeholders to codevelop and implement shared, electrified, and eventually autonomous mobility solutions in cities designed for them. Working with U.S. cities, it leverages emerging technologies and new business models to reduce congestion, decrease costs, increase convenience, enhance safety, curb emissions, and ensure economic growth. Please visit http://www.rmi.org/mobility for more information.

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ES EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

With electric vehicles (EVs) coming on fast thanks to undeniable advantages in the cost of ownership and the driving experience itself, it's time to move on from the old debates about when the EV revolution will arrive. It's here. We should not allow the fact that EV sales in 2016 were only about 1% of total light duty vehicle sales in the U.S. to lull us into a false sense of complacency. Under some reasonable assumptions, there could be 2.9 million EVs on the road in the U.S. within five years, bringing over 11,000 GWh of load to the U.S. power grid, or about $1.5 billion in annual electricity sales.[1] That would constitute a nontrivial load that utilities would need to accommodate well within their current planning horizons, and would almost certainly be the largest growth sector in the U.S. electricity market for the foreseeable future.

There is no benefit to further delay, or to waffling over whether investing in charging infrastructure is a good idea. And the chicken-and-egg problem that has stymied the electric vehicle revolution thus far—no one wanted to build EV charging infrastructure until there were more vehicles, but nobody wanted to buy EVs until there was more charging infrastructure—will be swept away by a fast-growing fleet of increasingly affordable EVs that consumers love.

Sticker prices, model options, and range anxiety have long been impediments to electric vehicle adoption, but those barriers are set to fall within a few years. EVs are already cheaper to refuel, and in some cases, such as with high-usage fleet vehicles, they are cheaper to own than conventional internal combustion engine (ICE) vehicles. EVs are on track to sport lower sticker prices than ICEs in Europe by next year, in China by 2023, and in the U.S. by 2025, without incentives or subsidies.[2] By 2020, there will be 44 models of EVs available in North America, and several best-selling models can already go more than 200 miles on a single charge.[3]

These trends, combined with emerging municipal and state targets for EV adoption and charging infrastructure deployment, indicate that the electric vehicle revolution has already begun.

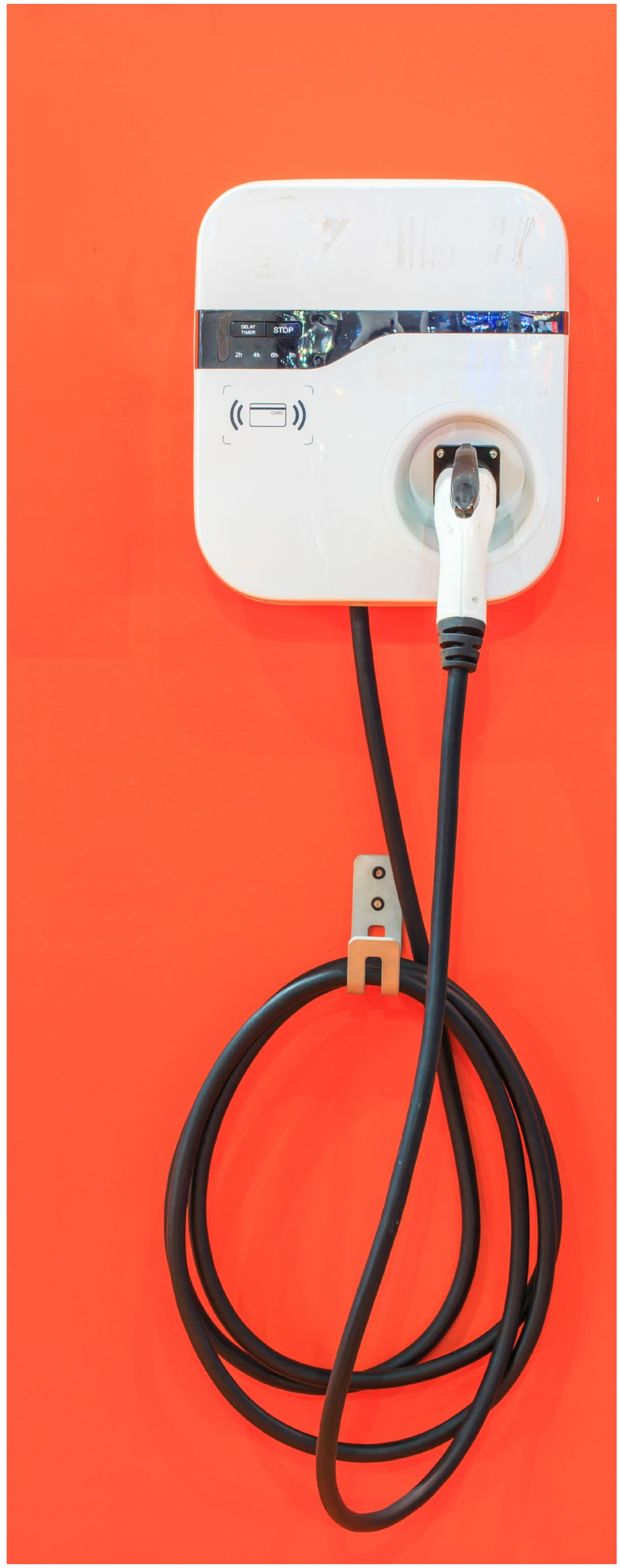
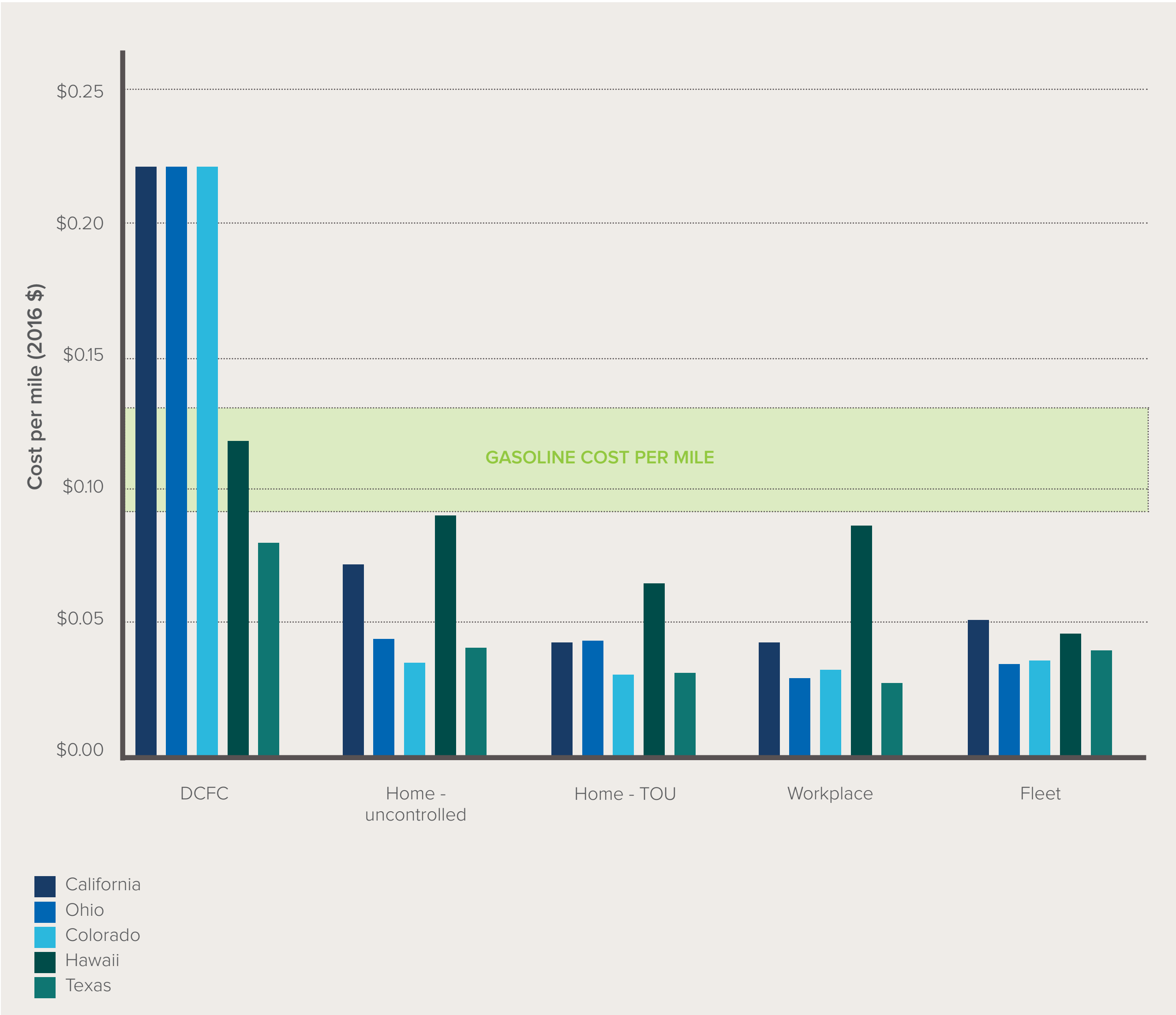


FIGURE 1

RETAIL COST TO EV OWNER, OR EMPLOYER OF EV OWNER, TO CHARGE ONE MILE OF EV RANGE UNDER DIFFERENT UTILITY TARIFFS AND DCFC PROGRAMS

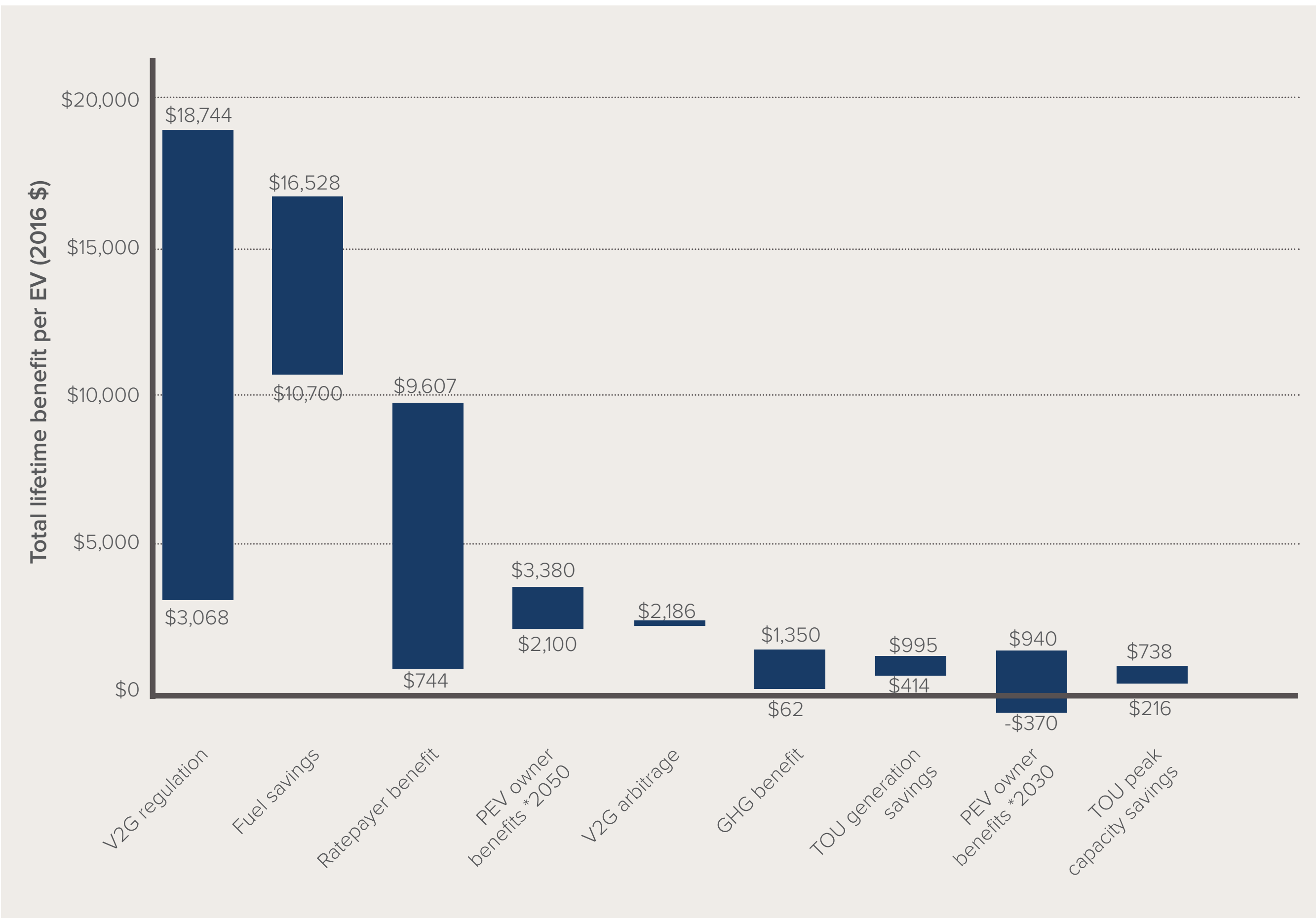


Unlike gasoline vehicles, EV owners have several options for refueling their vehicles. As we show in Figure 1, the cost to fuel an EV varies significantly depending on where the vehicle is charged, what type of charger is used, and the utility powering the charger. In the five states we feature in this report, the cost to charge an EV can be as high as $0.22/mile and as low as $0.03/mile, while the cost of fueling a gasoline vehicle varies in a much narrower band between $0.13/mile and $0.09/mile. Where and when EV owners will refuel their vehicles depends largely on where charging infrastructure is installed and the prices that EV owners encounter, which can vary widely depending on the utility tariff.

The world doesn't need any more cost-benefit analyses; they've already been done, and they show that vehicle electrification has numerous benefits for drivers, utilities, communities, and society as a whole. After reviewing over 150 pieces of recent literature on EVs, we summarized the quantifiable benefits, including greenhouse gas reduction, gasoline savings, savings for all utility customers, savings in system investment, fuel and maintenance savings, and the potential for managed charging of EVs to deliver various grid benefits.

FIGURE 2

RANGE OF STAKEHOLDER BENEFITS FOR EVS FROM THE LITERATURE [4]



The evidence from this research and analysis shows that vehicle electrification provides benefits that are so numerous and overwhelmingly positive for the public that we should no longer doubt the value of it, or become distracted to the point of inaction by arguments about equitability and best practices. Even non-drivers will benefit from the drastically reduced air pollutants of vehicle exhaust, the lower total cost of maintaining mobility infrastructure, and synergistic effects that can put downward pressure on the price of all goods and services, including the price of electricity and climate change mitigation measures. Some of these benefits will depend on smart management of EV charging loads, as we detailed in our 2016 report *Electric Vehicles As Distributed Energy Resources*.[5]

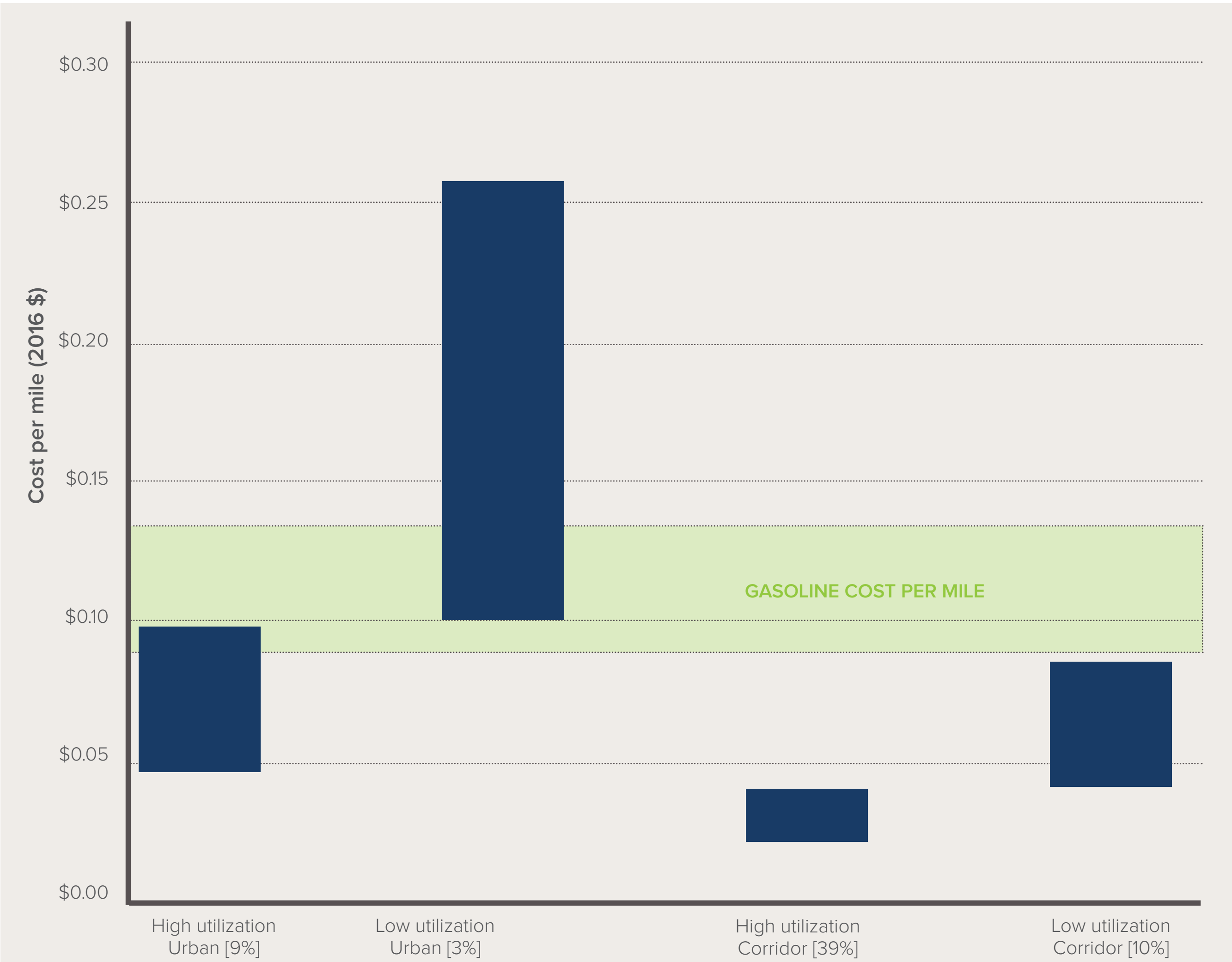
Based on this evidence, we conclude that vehicle electrification isn't an *if* or a *when* question anymore; it's only a question of *how fast* and *Can we be ready in time*. With EV adoption sporting compound annual growth rates of 30–40% in recent years in the U.S., the path to an electrified future is now simpler and more straightforward than it has ever been. The vehicles are coming, and we don't need to question that any longer. What we need to do now is to understand how and where to build charging infrastructure, and then start building it to meet the demand of oncoming EVs in as energy- and capital-efficient a way as possible. This report identifies the key hurdles that have inhibited the growth of charging infrastructure, and explains how they might be overcome, along with the best practices for siting chargers and designing electricity tariffs for EV charging stations.

However, deploying charging infrastructure for optimal benefit to all will require careful planning, robust testing and pilots, and appropriate incentives. Planners need to consider how many and what kinds of chargers will be needed and where, both now and in an autonomous ride-hailing EV future—preferably without stranding charging assets along the way. They will need to consider what the best paths are for charging station deployment, given sometimes-conflicting priorities specifying that public investments should be low-cost, high-utility, equitable, free-market oriented, and expeditious. The current patchwork network of vehicle charging infrastructure in the U.S. is still small enough and young enough that we lack sufficient data and rigorous analysis to answer many of these questions. Where this is the case, regulators and other stakeholders should not delay, but rather design effective pilots that can answer these questions and then scale into full programs—and fast.

The path that a given utility or state might take into vehicle electrification will vary according to different configurations of several fundamental factors, such as whether the regulatory environment dictates vertically integrated utilities or a "decoupled" utility business, available state and utility incentives, driving patterns, the grid power generation mix, load patterns on the local grid, climate and social objectives, and various kinds of costs. State and municipal officials who would promote vehicle electrification in their jurisdictions will need to understand how these factors can work for or against a given electrification strategy. For example, our research shows that direct-current fast charging (DCFC)—also known as fast charging—in an urban environment is much more costly than refueling a conventional gasoline vehicle, and that DCFC charging costs can vary widely from state to state and utility to utility.

FIGURE 3

ELECTRICITY COST FOR HOST SITE TO DELIVER ONE MILE OF CHARGE VIA DCFC



To demonstrate the different paths that result from various combinations of these factors, we look at five U.S. states: California, Colorado, Hawaii, Ohio, and Texas. For each of these states, we investigate and critique:

- The current state of charging station deployment and ownership, and strategies for further charging station deployment
- The regulatory structure of the state, and the implications of that structure for charging station deployment
- The economics of EV ownership
- The cost of owning a charging station under several charging scenarios and types of charger locations
- How chargers are likely to be used
- Utility tariffs for EV charging stations
- The potential benefits that managed charging could provide to the state's power grid
- Additional benefits of vehicle electrification

TABLE 1

EV AND EVSE DEPLOYMENT STATISTICS BY STATE [6]

	EV PENETRATION	EVS ON THE ROAD	NUMBER OF EVS PER L2 CHARGER	NUMBER OF EVS PER DCFC
CALIFORNIA	2.10%	299,038	27	196
HAWAII	1.20%	6,178	14	88
COLORADO	0.56%	10,033	12	76
TEXAS	0.23%	18,930	10	73
OHIO	0.15%	6,973	16	52

Ultimately, our message in this report is that EVs of all sizes, shapes, and applications are coming quickly. Utilities, their regulators, states, and municipalities need to be prepared to implement programs now that will transform the mobility marketplace. States that are ahead of the curve on EV integration will enjoy lower total transportation costs, lower emissions, and a more efficient grid, and will likely be perceived as more favorable business climates able to attract a high-quality labor pool seeking high-quality lifestyles. Conversely, states that fall behind the curve are likely to face a sudden need to install expensive infrastructure and generation for peak capacity, possibly leading to a less-efficient grid with higher prices for consumers. The rapid and unplanned adoption of air conditioning 50 years ago put grid operators in just such a position, and it could happen again now, only at a much larger scale and a much higher cost. It is absolutely critical to get right the programs and infrastructure for vehicle electrification from the start, with appropriate tariffs, well-planned charging infrastructure, and the ability to manage chargers either directly or through aggregators.

With careful planning and early intervention, the electric vehicle revolution can help optimize the grid and reduce the unit cost of electricity, while increasing the share of renewable electricity and reducing emissions in both the electricity and transportation sectors.[7] Passive management techniques, such as using time-of-use (TOU) tariffs to motivate drivers to charge at off-peak times, offer a simple and easily implemented way for utilities to use the charging load of EVs to provide dynamic, real-time grid regulation services, and to provide a flexible load to meet supply. Actively managing the charging of EVs via aggregator companies, or even via direct utility control, may also be useful, although the methods for doing so are still fairly nascent. By using EVs to absorb excess solar and wind, utilities can avoid curtailment of those generators, increase their share of the total electricity supply, and possibly displace or avoid the need for conventional fossil-fueled generation. Utilities can realize these benefits starting now, with each new EV that appears on their grids. There is no benefit to delaying exploring how to accommodate EV loads intelligently.

Areas that are just beginning to install public charging stations may want to begin with a pilot program in a high-use retail area or commuting corridor. Communities that have already done pilots may want to turn insights gained from them into a more comprehensive plan, and start building charging stations in earnest. Every charging station that is deployed should deliver useful data that can be captured and analyzed to help decision makers understand the value/risk proposition of vehicle electrification in their communities. Regardless of how far along they are in deploying charging stations, all communities would be well advised to gather data from pilot projects and then use it to inform subsequent deployments as the charging network scales up. Without careful and early planning, robust testing, and demonstration projects, we could wind up with a lot of inefficient and expensive generation capacity with low load factors, unnecessary transmission and distribution infrastructure permanently embedded into utility rate bases, a network of chargers that doesn't provide cost-effective and accessible support for EVs, higher costs, and unnecessary strife in regulatory proceedings as utilities, interveners, and regulators struggle to catch up and repair damage that was entirely avoidable.

Our message is clear and simple: Building EV charging infrastructure should be an urgent priority in all states and major municipalities. Getting it right will require unprecedented cooperation by many stakeholder groups. The time to act is now.

01 THE EV REVOLUTION IS HERE

Tesla model 3, image © Tesla

THE EV REVOLUTION IS HERE

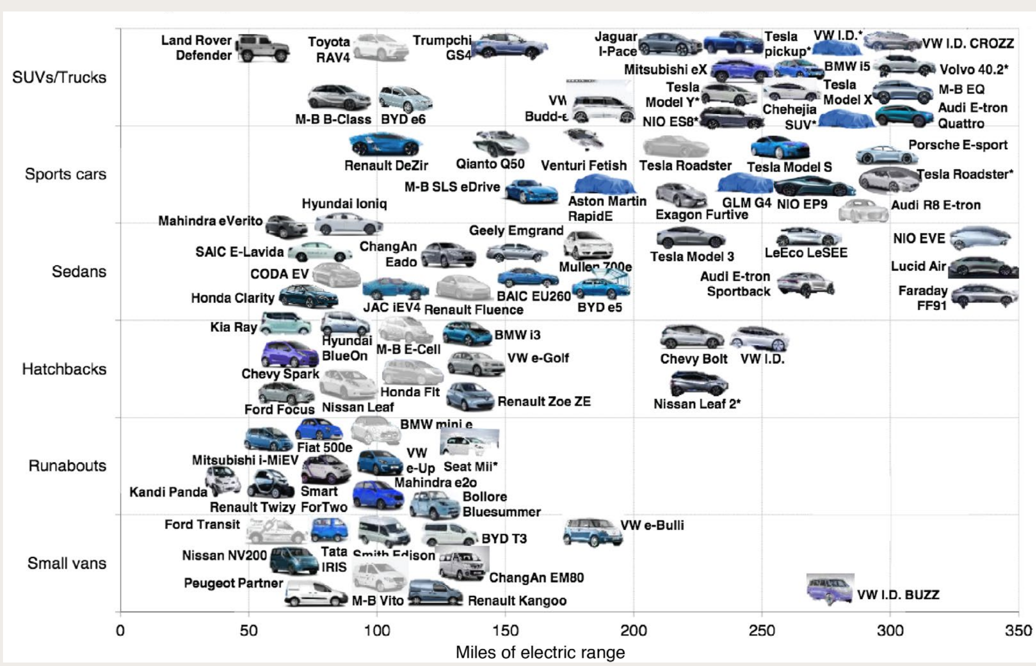
Consumers who have EVs love them. The top four vehicles in the 2015 Consumer Reports Annual Auto Survey were all either full-electric vehicles (aka battery electric vehicles, or BEVs) or electric plug-in hybrid electric vehicles (PHEVs).[8] Their smooth rides, low noise, lack of exhaust, fast acceleration and superior torque, very low maintenance needs, and fueling costs at about one-third of an internal combustion engine (ICE) vehicle, make electric vehicles far more enjoyable to drive and cheaper to own.[9]

The hurdles to widespread consumer adoption of EVs are well known: higher purchase prices, a limited number of models, range anxiety, and a lack of public charging infrastructure (charging stations that are available without restriction to the public). But the first three of those hurdles are now falling.

After tax credits, there are now 15 models of EVs available from major manufacturers under $30,000, which is the price at which widespread adoption is generally considered likely. Of those models, 10 have at least a 50-mile range in all-electric mode.[10] Many more models are expected by 2020, and Ford expects that, within 15 years, the number of EV models available will be greater than the number of ICE models. Ford alone plans to ship 13 EV models in the next five years.[11] Volkswagen has announced that it intends to launch 30 models of EVs over the next nine years.[12] Volvo projects that all of its new models will include electric drive by 2019.[13] BMW and Mercedes-Benz expect EVs to be 15–25% of their sales by 2025.[14] Even Porsche, a longtime holdout on making EVs, has announced that it now thinks electric models will be half of its production by 2030.[15] Bloomberg New Energy Finance anticipates that by 2020, there will be 39 models of PHEVs and 44 models of EVs available in North America.[16]

FIGURE 4

SAMPLE OF EV MODELS AVAILABLE THROUGH 2020



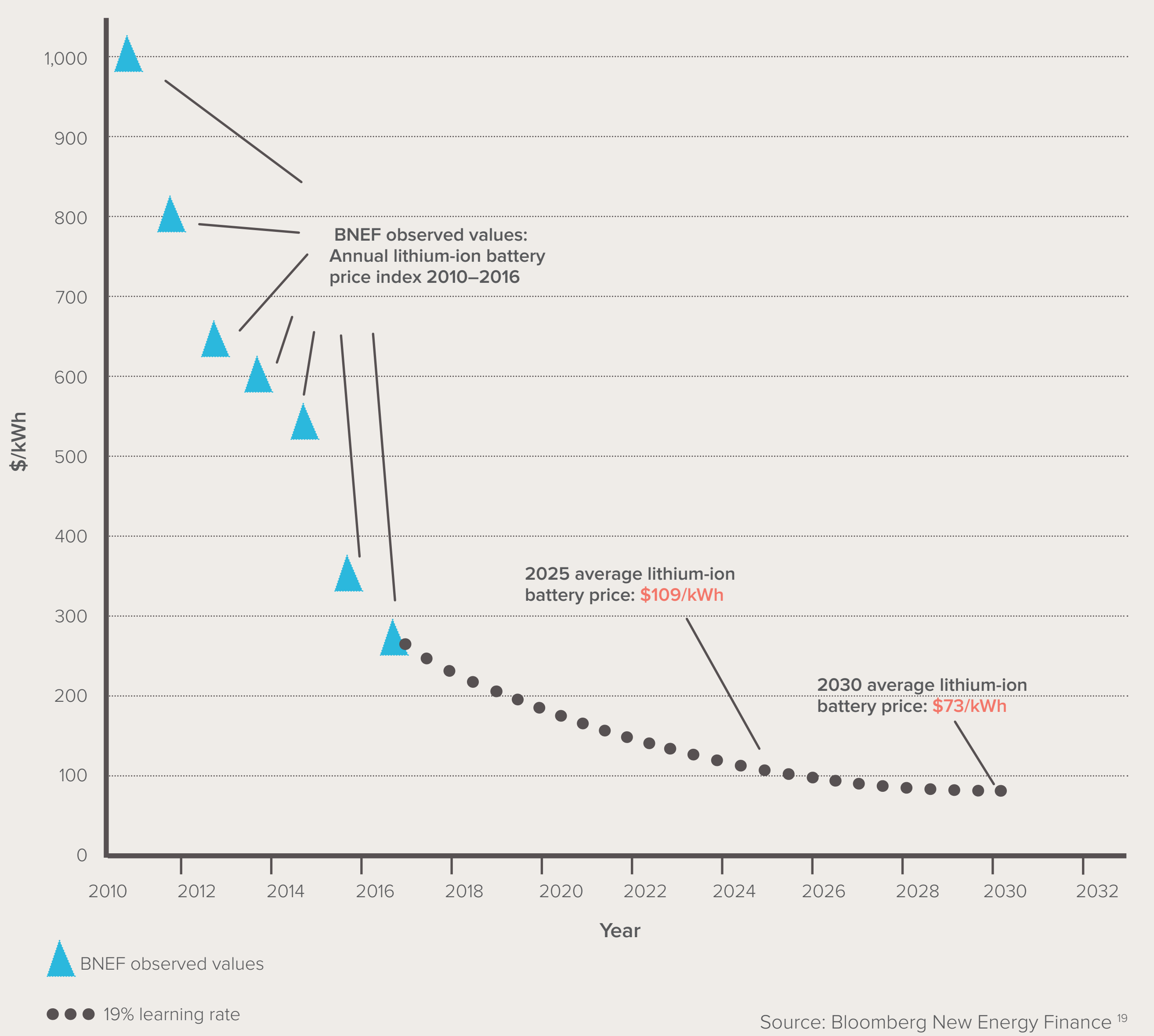
Source: Bloomberg New Energy Finance [17]

Exhibit JRB-5

The falling cost of EVs is due primarily to the falling cost of battery packs and to vehicle manufacturers moving beyond the production of EVs merely to serve as "compliance cars." That trend looks set to continue with numerous gigawatt-scale lithium-ion battery factories under planning and construction around the world, and an expected sharp increase in vehicle sales by 2020. Bloomberg New Energy Finance expects the price of lithium-ion battery packs to fall 43% by 2021, from $273 per kilowatt-hour today to $156.[18]

FIGURE 5

BNEF FORECAST FOR THE COMBINED COST OF LITHIUM-ION BATTERY CELLS AND PACKS



Source: Bloomberg New Energy Finance [19]

Lower battery costs mean that it's now feasible to calm range anxiety at an acceptable price.[20] The base model Tesla Model 3, which has begun shipping, sells for less than $30,000 after the federal tax credit and sports at least 215 miles of range (and up to 300 miles with an optional larger battery).[21] The 2017 Chevrolet Bolt can be had for less than $30,000 after the federal tax credit, and has a 238-mile range. And by 2020, Ford plans to launch a mass-produced crossover utility model with at least a 300-mile range, which will be priced competitively for the mass consumer market.[22]

The falling cost of EVs has increased sales, and accelerated sales seem destined to continue. Worldwide EV sales in 2016 were up 42% over 2015, and U.S. sales were up 36% over 2015.[23] Total SA, a major oil company, believes EVs will make up 15–30% of new-car sales by 2030.[24] In China and India, the new growth markets for vehicles globally, EVs are expected to take significant market share. China's "road map," released in April 2017, calls for 20% of new vehicle sales to be alternative fuel vehicles by 2025. And in India, the government is aiming for full electrification of all vehicles by 2032.[25]

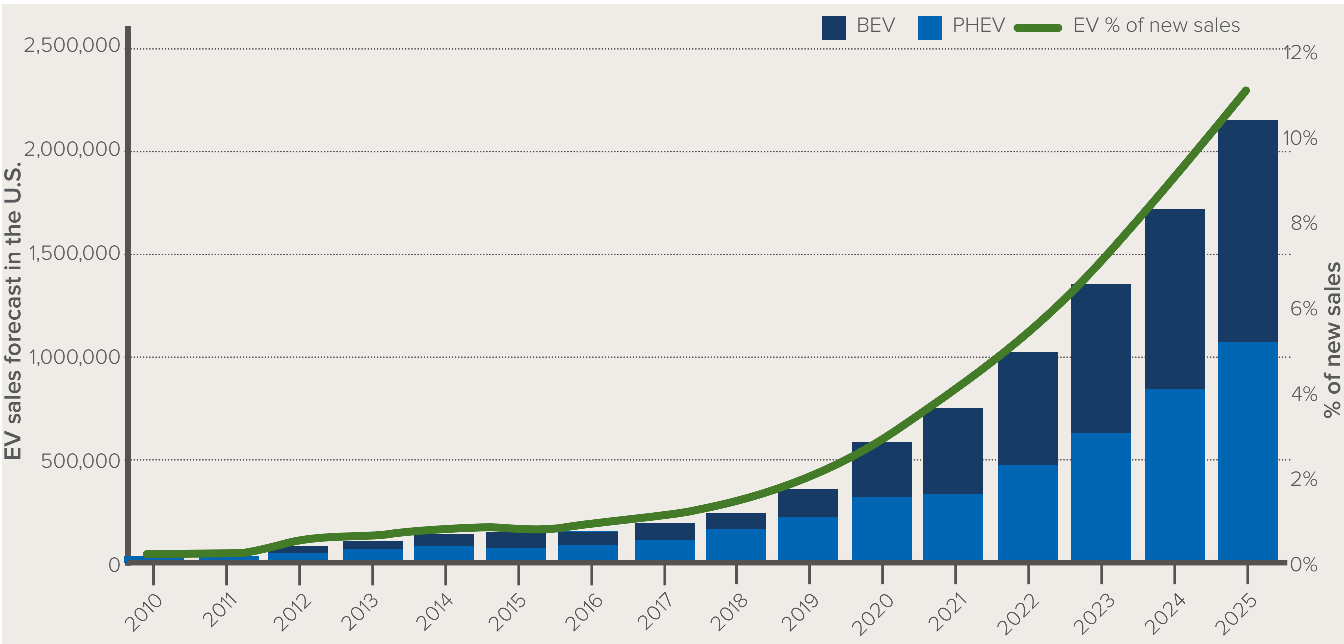
The ongoing battery-cost reductions are finally making EVs competitive with ICE vehicles. According to the investment bank UBS, EVs are approaching cost parity with equivalent ICE vehicles far more quickly than previously expected, as battery costs plunge, actual rock-bottom maintenance costs become more evident, and EV adoption rates accelerate.[26] UBS believes that in Europe, the total cost of ownership of an EV is already nearly equal to that of an equivalent ICE vehicle. It expects cost parity on a total cost of ownership basis to be reached in Europe by next year, in China by 2023, and in the U.S. by 2025, without incentives or subsidies. And although vehicle manufacturers are currently losing money on EV sales on an EBIT (earnings before interest and taxes) basis, UBS sees a positive 5% EBIT margin in Europe by 2023, in China by 2026, and in the U.S. by 2028.

Even consumers who don't think about the total cost of ownership and only look at the sticker price will soon be convinced that EVs are cheaper. Bloomberg recently suggested that EVs could be cheaper than their ICE equivalents by 2030.[27] Additionally, the second-hand market for EVs, which is only just getting started, will make earlier models of EVs attractive to segments of the market for which premium-priced vehicles were out of reach.

A central EV sales forecast from Bloomberg New Energy Finance sees U.S. EV sales rising to over 640,000 per year by 2021; however, it thinks it's also possible that annual EV sales in the U.S. could rise to nearly 800,000 by 2021, with Tesla selling 250,000 of them.

FIGURE 6

BNEF EV SALES FORECAST THROUGH 2025



Source: BNEF[28]

In addition to the market pull of lower prices, EVs will benefit from a variety of policy pushes. For example, both Britain and France have pledged to ban all new petrol and diesel cars and vans after 2040.[29] The Netherlands, Norway, and Germany have contemplated implementing similar bans as soon as 2025.[30] The mere specter of such policies is likely to accelerate EV adoption, even in the U.S., as elected officials and drivers seek to position themselves advantageously in advance of a well-telegraphed major market shift.

"The future is definitely electric, no question in my mind, it's more of, 'what is the future timeline?' Is it 10 years, 15 years, 40 years?... We don't see an alternative more interesting [than] that, it's just a matter of what the adoption hits at the scale that makes this a slam dunk."

–Tom Gebhardt, Chairman and CEO of Panasonic's North American operations[31]

Sticker prices, model options, and range anxiety will soon disappear as impediments to the adoption of electric vehicles. In fact, the economics and emerging policy targets for EVs indicate that the EV revolution is all but inevitable. It's not an *if* or even a distant *when* question anymore; it's more one of *Can we be ready in time?* EV sales could hit the rapid-growth part of the technology-adoption S-curve as soon as 2026, in the estimation of Bloomberg New Energy Finance,[32] and given the typical lead time on utility infrastructure investments, that might as well be tomorrow. In our view, the balance of risk now tilts toward deploying charging stations too late and with insufficient advance planning, not too early. And there is no benefit to delaying preparations for intelligent EV load management. Utilities can realize the benefits of EV-grid integration today, and increase their learning with each new EV that appears on their grids.

The missing link now is widely available charging infrastructure. How and where to build the charging network, and who should build it, is the subject of this report.

ACCELERATING THE EV REVOLUTION: SHARED MOBILITY AND VEHICLE AUTONOMY

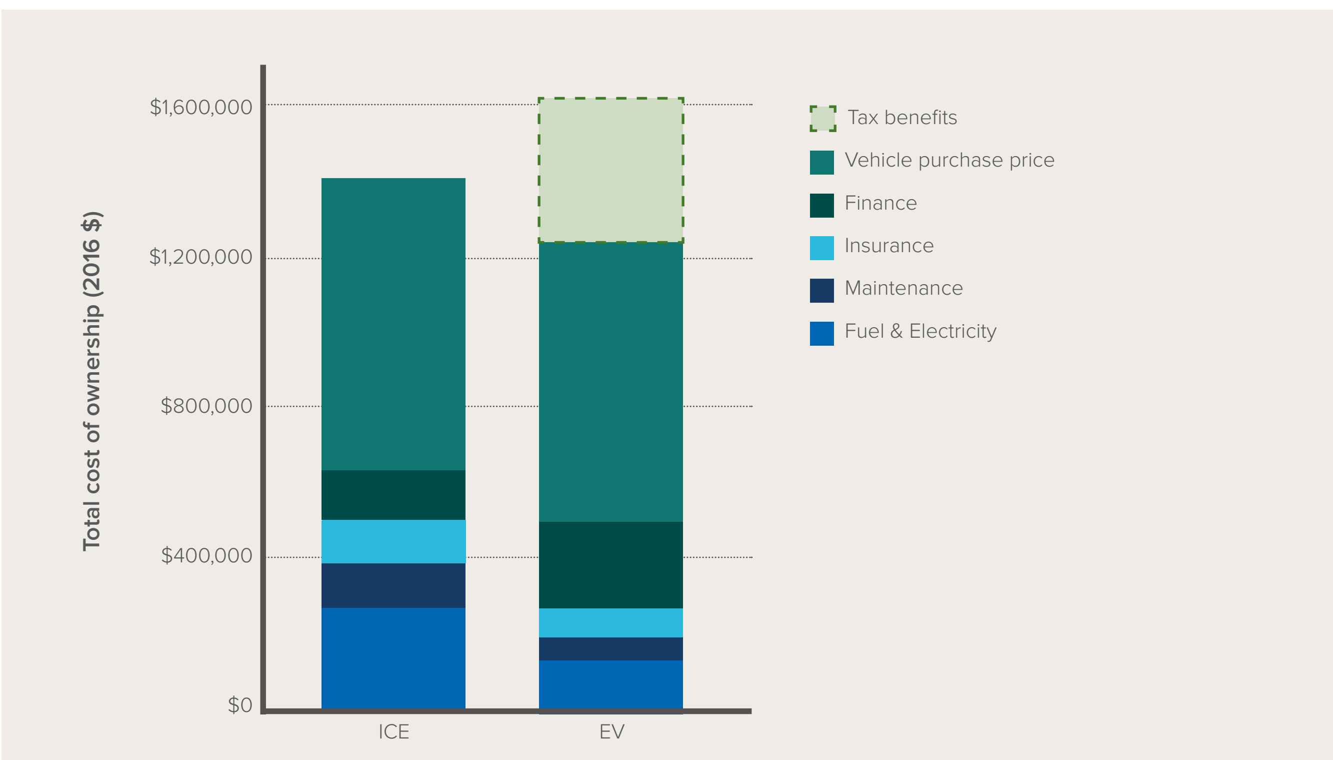
High-usage fleet vehicles are prime candidates for electrification. The total cost of ownership is already lower for EVs than for conventional ICE vehicles. By concentrating charging at purpose-built charging depots, where capital costs can be spread over a larger number of charging events and charging behavior can be managed to provide valuable grid services, fleet operators can lower charging costs further. What has been lacking for operators of EV fleets is sufficient charging infrastructure of this nature.

Fleets can also be managed to use public chargers (chargers that are available without restriction to the public) during times of low demand, and help to optimize the use of those chargers. For example, GM's Maven car-sharing service has found that ride-hailing services using their vehicles tend to charge at times of the day when existing DCFC networks have low utilization, as in the mornings and later in the evenings. DCFC owners could offer time-varying prices for using their chargers that would encourage drivers to charge at times of low demand, which would help fleet operators save money and help DCFC owners increase their utilization rates.

Figure 7 shows the five-year total cost of operation (assuming a 10% discount rate) for a fleet of 30 Chevy Bolts driving 25,000 miles per year, and compares those costs to the cost of operating a fleet of 30 compact ICEs, based on average ICE fleet cost and performance.[33] (See the Appendix for details on the methodology of this analysis.) These results demonstrate the favorable economics of EVs in fleet

FIGURE 7

FIVE-YEAR TOTAL COST OF OWNERSHIP NET PRESENT VALUE FOR A FLEET OF 30 VEHICLES IN COLORADO, ICE VS. EV



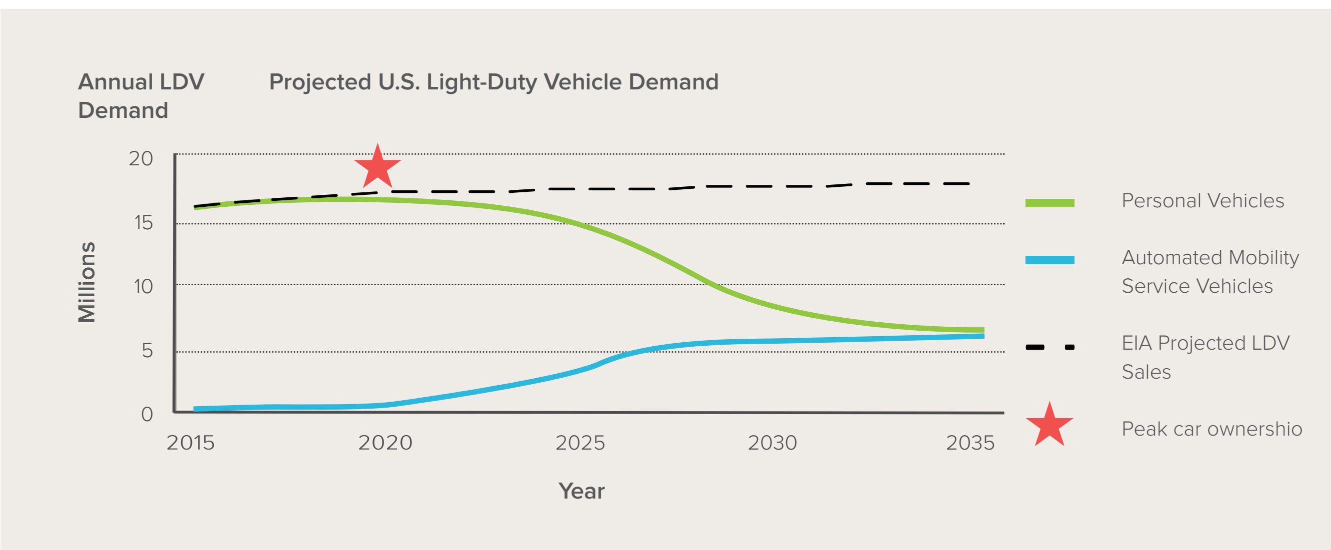
deployment under current capital and operational costs after federal and Colorado state-level tax rebates. As shown in the chart, the primary savings are from lower maintenance and fuel costs. However, those savings are largely offset by the cost premium of the EV. The capital cost of the Chevy Bolt is roughly $10,000 higher than a typical ICE counterpart, and federal and state tax credits are currently necessary to tip the total cost of ownership in favor of EVs. However, as battery costs continue to decline and production volume increases, the tax credits will no longer be needed and EVs will be economically favorable over ICEs without the help of subsidies.

AND THE SELF-DRIVING PHASE OF THE REVOLUTION IS EN ROUTE

The takeover of the personal vehicle market by EVs will be accelerated by the penetration of autonomous (self-driving) vehicle technology. Rocky Mountain Institute's 2016 report, *Peak Car Ownership*, estimated that shared autonomous electric vehicles (SAEVs) could obtain roughly a one-third share of the market for light-duty vehicles by the late 2020s.[34] According to our model, automated mobility services could capture two-thirds of the entire U.S. mobility market in 15 to 20 years, starting with urban areas. Other forecasters are even more bullish. RethinkX projected in its 2017 report, *Rethinking Transportation*, that SAEVs will account for nearly all light vehicle sales by 2030 as ICE vehicles are made obsolete, rendering 97 million of them "stranded."[35]

FIGURE 8

PROJECTED LIGHT-DUTY VEHICLE DEMAND.



Source: *RMI*, Peak Car Ownership (2016)[36]

The Brattle Group observes that the many advantages of SAEVs over individually owned ICE vehicles could engender their rapid adoption, apart from other pressures like decarbonization or utility programs to increase load. Lower accident and fatality rates, better access to mobility for underserved populations, reduced need for urban parking spaces, reduced traffic congestion, better air quality and lower overall transportation costs will all attract riders and reduce the appeal of owning and driving a vehicle.[37]

Automakers are increasingly invested in the SAEV future as well. Uber has been testing autonomous vehicles in Pittsburgh, PA; San Francisco; and Tempe, AZ. Lyft and Waymo have announced their own collaboration on autonomous vehicles. Ford, Volvo, Tesla, GM, Volkswagen, Honda, and Audi have all made investments in self-driving technology, and some have begun testing autonomous vehicles. Tesla alone has already logged more than 200 million "autopilot" miles. Ford has announced that it will mass-produce autonomous vehicles for use in ride-hailing services (with no steering wheel) by 2021. Google, Apple, Intel, and other major tech firms have also been making substantial investments in autonomous vehicle research and development.

Whether the SAEV future arrives in this decade, or several decades from now, if it is well planned and executed and built on an EV platform, it can be safer, cheaper, more enjoyable, and more environmentally friendly than today's personal transportation regime. In fact, its benefits could be so numerous as to make it inevitable.

But between now and then, we will need to deploy charging infrastructure, both for today's rapidly growing fleet of EVs, and for SAEVs when they arrive in large numbers. As we discuss in "The impact of 'Dieselgate'" on p.35, it will be important to consider the different charging needs and adoption rates of electric personally owned vehicles (POVs) and fleets of SAEVs, and plan the deployment of charging stations accordingly.

"'There is a major disruption looming there,' [Apple CEO Tim] Cook said on Bloomberg Television, citing self-driving technology, electric vehicles and ride-hailing. 'You've got kind of three vectors of change happening generally in the same time frame.'"[38]

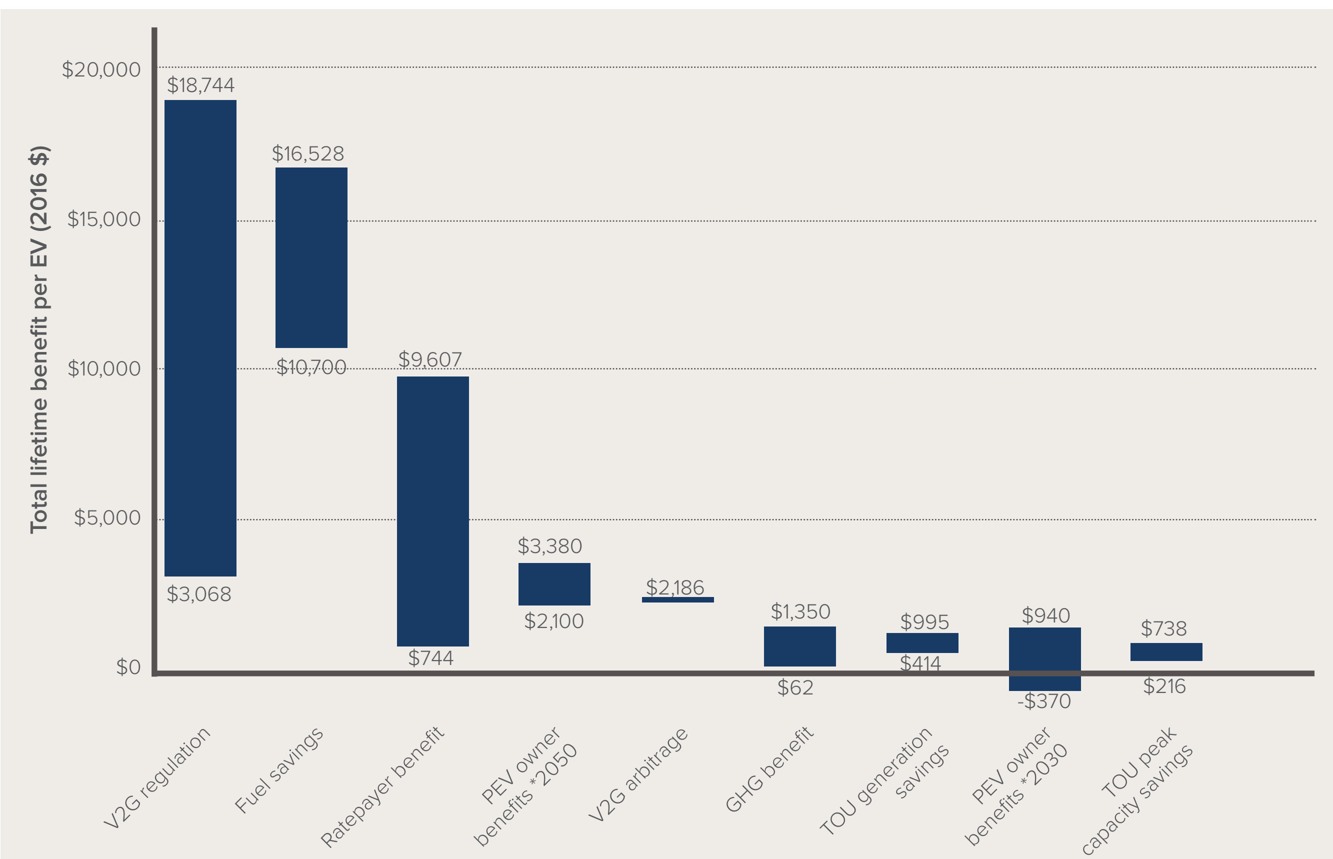
02 THE ECONOMICS OF EVS AND GRID INTEGRATION

THE ECONOMICS OF EVS AND GRID INTEGRATION

Numerous studies from across academia, think tanks, consulting firms, and industry trade groups have exhaustively analyzed the costs and benefits of vehicle electrification. Often these studies present the value and cost of electric vehicles from a single stakeholder perspective and consider only a subset of the full range of values EVs offer. In this report, we aggregate and then normalize results from 11 studies and present the values in dollars per EV, over the lifetime of the vehicle, in 2016 dollars. As shown in Figure 9, the values vary significantly within value categories as well as across them. This range can be attributed to many factors, including but not limited to: electricity market, utility regulation, battery size, tariff structure, generation mix, distribution system age and capacity, and vehicle characteristics (see Appendix for detailed tabulated values). What this exercise demonstrates most clearly is that EVs provide value to all stakeholder groups, but characterizing that value in a generalized way is not useful, due to the myriad variances from place to place. However, we can make the general assertion that when EVs are properly integrated with the grid, they provide value to both customers and the grid, but maximizing the value (and avoiding unnecessary costs) will require thoughtful planning and collaboration across all stakeholder groups. It will also require some courage on the part of decision makers to test early and take action before substantial demand materializes, in the interest of protecting utility customers and society as a whole from hasty, late, and poorly considered infrastructure investments.

FIGURE 9

RANGE OF STAKEHOLDER BENEFITS FOR EVS FROM THE LITERATURE[39]



Below we provide a brief description of the major EV benefit categories.

Gasoline savings – The difference in the cost of fueling an average ICE vehicle as compared to its EV counterpart. This value is sensitive to gas and electricity prices as well as to the assumed fuel economy of the vehicle.

Utility customer benefits – Benefits to utility customers are often calculated using a standard ratepayer impact measure (RIM). The RIM is a calculation that measures what happens to a customer's bill due to changes in utility revenues and operating costs resulting from implementing a new program or tariff. In the case of EV-specific rates or programs, a positive RIM means the revenue generated from EV charging is higher than the marginal cost to serve those customers and thus creates downward pressure on all rates.

Time-of-use generation savings – The difference in cost of energy generation when vehicles charge during the off-peak hours of a TOU rate. This value is highly dependent on the generation mix and the economic dispatch order of the generator fleet. This value is not a net benefit to the grid or to an EV owner. Rather, it should be considered a cost that can be avoided if drivers respond to a time-varying rate designed to reduce on-peak consumption.

Time-of-use peak capacity savings – The avoided cost of building new peaking capacity that can be realized by managed charging as compared to uncontrolled charging. This value is not a net benefit to the grid or to an EV owner. Rather, it should be considered a cost that can be avoided if drivers respond to a time-varying rate designed to reduce on-peak consumption.

PEV net owner benefit – The net benefit or cost of owning a plug-in electric vehicle (PEV) as compared to an ICE vehicle. This value is highly dependent on the capital cost of the vehicles, the fuel economy, the fuel price, and the driving patterns of the vehicle owner. However, it is clear that fueling and maintenance costs for EVs are considerably lower than for ICE vehicles.

GHG benefit – The value of avoided greenhouse gas (GHG) emissions as compared to a typical ICE vehicle, based on the GHG emission intensity (the emissions per unit of grid power generated) for a specific utility or region, and an assumed vehicle fuel economy. This value is typically derived from an assumed \$/ton CO_2 and is often assumed as an externality that is typically not monetized.

V2G regulation – The value of vehicles responding to frequency regulation signals by sending electricity back to the grid, using vehicle-to-grid (V2G) technology. This value is highly dependent on the power capacity of the battery and the electricity market in which it is participating. These values are fairly theoretical, as there are currently no major utilities or vehicles that allow V2G operation at commercial scale in the United States.

V2G energy arbitrage – The value that can be captured by charging an EV battery during low-cost periods and then selling that energy back to the grid during high-cost periods. These values are fairly theoretical, as there are currently no major utilities or vehicles that allow V2G operation at commercial scale.

G2V services – Although they are currently hard to quantify because they are so new that empirical data is hard to come by (hence their absence from Figure 9), managed charging can provide numerous ancillary services to the grid, as we detailed in our 2016 report, *Electric Vehicles as Distributed Energy Resources*.[40] These services include demand response, frequency regulation, voltage regulation, and other technical grid support services, and are sometimes collectively referred to as grid-to-vehicle (G2V) services. Rather than sending energy back to the grid as with V2G services, G2V services are typically provided by an aggregator who turns a group of charging stations off (or down) when the grid is stressed, or when the utility issues a demand-response request. This service does not require bidirectional inverters, but it does require that vehicles charge at rates lower than their maximum capacity to allow for "regulation down" events (e.g., vehicles increase their charging rate to lower grid frequency).

Understanding how to interpret and apply these benefits can be a complicated task. Although a single EV can and does provide these benefits, it is not possible to simply add them up to arrive at a single net benefit, partly because providing one service can limit the opportunity to realize value from another service. For example, one might have to be charging during an on-peak period of a TOU rate in order to be available to provide a frequency response service to the grid. Or charging only during the off-peak hours of a TOU rate may mean charging during times when the GHG emission intensity is higher (for example, charging overnight when coal is the marginal generator on some grids) and thus reducing the GHG-reduction value. This would not be the case where TOU rates are designed to shift charging to periods of excess renewable generation, as is increasingly the case in California.

Therefore, integrating large quantities of EVs into our electricity system will be a challenging optimization problem that must consider the needs of the EV owner or fleet operator, while also considering what is most cost-effective for the grid, in addition to other social goals like decarbonization and equitable access to charging facilities. This necessarily requires granular and intelligently designed price signals that will allow users to make economically guided decisions.

03 GET READY

Charging stations, courtesy of Felix Kramer

GET READY

EV sales in the U.S. have been growing at a compound annual growth rate of 32% for the past four years, and monthly 2017 sales data suggests that the sales rate is accelerating sharply. Under some reasonable assumptions, there could be 2.9 million EVs on the road in the U.S. within five years, bringing over 11,000 GWh of load to the U.S. power grid, or about $1.5 billion in annual electricity sales that utilities will need to accommodate well within their current planning horizons.[41]

It's time to focus on how to deploy charging infrastructure, so that we can do it deliberately, at the lowest possible cost, and with the greatest possible benefit, instead of reactively, inefficiently, and ineffectually.

BARRIERS TO DEPLOYING INFRASTRUCTURE

The best practices in deploying charging infrastructure may vary from place to place. The arguments against deploying charging infrastructure may vary from place to place too, depending on the regulatory environment, the popular perceptions of EVs, and other factors. We interviewed nearly two dozen experts on EV-grid integration to get their perspectives on the common arguments they have heard against investing in charging station networks. Here, we address those arguments.

THE COST OF INSTALLING CHARGERS IS TOO HIGH

There are three major types of charger, and their costs are very different. (See Table 2 Types of Chargers on p.33 for details.)

Level 1 charging is built into every EV, so the only cost is for an extension cord to run from the vehicle to a standard wall outlet.

Level 2 charging requires the installation of a special charging unit and access to 240V service. The cost of installing a Level 2 charger can run from around $500 (to buy a unit off the shelf and install it at home) to around $6,000 (for a commercial public installation involving removing and replacing concrete, trenching, running conductors, and other tasks). The cost of installing a bank of Level 2 chargers, for example at a workplace or shopping mall, is therefore not negligible.

DCFC chargers are expensive, typically running around $50,000 per charger installed, although some installations can cost considerably more. With so few DCFC chargers installed across the U.S., there is limited cost data available, and it varies widely. After including costs for project development, design, permitting, and system upgrades, it's not unusual for the total cost of DCFC deployment to run as high as $300,000 each. These costs limit the business opportunity for public DCFC chargers. Unfavorable rate design (see "Tariffs" on p.42) exacerbates the challenge, and low utilization rates (because there aren't yet enough EVs on the road) make it very difficult to show the business case at present. At a retail price for electricity that would be on par with fueling with gasoline (around $0.29/kWh, according to our analysis,[42] or around $0.09–$0.13/mile cost to the driver), recovering the capital from DCFC investments is extremely slow.

SOLUTION

Rebates or other incentive programs for homeowners and businesses to install Level 2 chargers for customers and employees are a relatively low-cost way to satisfy charging needs over the next decade while offering the greatest grid-interactive flexibility. Therefore, ubiquitous deployment of Level 2 chargers should be a top policy objective. Many utilities already offer rebates on home and workplace charging stations. With modest support, it should be within reach of most homeowners and commercial businesses to install an appropriate number of charging stations to support their own personal needs or those of their employees and customers.

DCFC installations will need more than rebates; specifically, they will need larger amounts of "patient capital" to support their installation and operation for a decade or longer. DCFC installations will need patient capital until there are enough EVs on the road to significantly increase their revenue and shorten their path to profitability, and until the market for these chargers has grown sufficiently to drive down hardware and balance-of-system costs. Numerous financing solutions, from municipal bonds and green bonds, to long-duration purchase agreements, to green bank investments, would be able to answer that need if investors had sufficient confidence in the inevitability of vehicle electrification. In the absence of that confidence, however, the most expedient path would be to allow utilities to rate-base at least the make-ready portion of charging infrastructure (providing wiring to the point where a charging station could be installed). And since all customers would share the benefits of the charging network eventually, that investment seems consistent with sound regulatory principles. However, it would behoove regulators to design such utility investments with performance-based incentives; see sidebar on p.38.

Alternatively, regulators could offer tariffs that shift costs away from private DCFC installers and owners (and onto the general rate base) to enable the private DCFC installers and owners to see a shorter path to profitability, which would in turn enable them to secure low-cost, long-term capital. Although RMI has done extensive research on rate design for new technologies, like EVs, and on the merits of advanced rate design in general, the details and theories of rate design, and the intended and unintended cost shifts between classes of utility customers is not the object of this report. It should be noted that regulators have varying views on whether utilities should be allowed to own charging infrastructure at all, as we discuss in “Ownership” on p.39. By the very design of the U.S. utility and regulatory system, this is a determination that each regulatory body must make for itself, within the scope of its authority and jurisdiction.

Tax relief for the installation and operation of DCFC could also stimulate investment and help lower the cost of capital. The current installed base of DCFC is relatively small and underused, but with a favorable tax structure, there will be incremental investments in equipment and incremental sales that will produce some incremental tax revenue, which can be shared with the investors in consideration for providing a public good.

Programs and credits, like California’s Low Carbon Fuel Standard credits, can also help to defray the cost of installing charging infrastructure, and help improve the business case for owning and operating charging stations.

REGULATORS AREN’T CONVINCED THE INVESTMENT IS WORTHWHILE

With few EVs on the roads in most places outside California, it has been difficult for regulators in many states to justify allowing utilities to invest in charging infrastructure and recover the costs through the rate base. While only a few drivers of expensive EVs are even able to use charging infrastructure, it’s easy to make the argument that spreading the cost of charging infrastructure over all utility customers amounts to shifting of costs from the rich to the poor. In the face of such a potent political argument, even the best of careful cost-benefit analyses can fail to engender the support of public utility commissioners.

SOLUTION

If vehicle electrification is now an unstoppable trend with proven and quantifiable benefits to society (as we discussed in “The Economics of EVs and Grid Integration” on p.22), and charging infrastructure is well-used, then the cost-shifting argument is really just based on a very near-term question about timing. Since the aforementioned BNEF and UBS projections indicate that EVs will see rapid adoption within two years and reach cost parity with comparable ICE vehicles in the U.S. within seven years, it is difficult to argue for further delay in making infrastructure investments. The availability of charging infrastructure will benefit everyone—even those who don’t drive—so distributing some of the costs of building it across the rate base can be justified. But, we hasten to add the caveat that such benefits will accrue *if the infrastructure is* *well used*. It would behoove regulators to ensure that utility investments are money well spent by employing performance-based incentives; see sidebar on p.38.

To invert the argument: Voluminous research has already shown that the social benefits of widespread vehicle electrification are many, and an electrified transportation regime would deliver more than enough social benefit to justify the investment needed to obtain a widely available and commercially viable network of charging stations. If we accept that getting to that point will require significant investment by the public because private companies can't do it on their own (as California's experience suggests; see "Ownership" on p.39), then costs would only be shifted during the first part of the adoption curve. Once owning and operating charging stations is a sustainably profitable business in its own right, the need for public investment would be minimal. In the meantime, investments by utilities and automakers like Tesla, which is building its own network of charging stations, will be important to getting the network built initially. And public investment made in charging infrastructure in order to obtain a long-term good that will benefit everyone is a right and proper use of public funds, especially if that good cannot be secured otherwise. Thus, public investment in charging infrastructure isn't a cost shift from one customer class to another; it's a cost shift from one time frame to another, and is a routine way of paying for things the public wants and needs, in exactly the same way that it pays for roads, water infrastructure, and the rest of the electricity grid.

UTILITIES AREN'T ACCUSTOMED TO CHARGING-INFRASTRUCTURE INVESTMENT

In order to justify investments in charging infrastructure, utilities may need to present complex cost-benefit analyses to regulators, including harder-to-quantify benefits like the effects of load-shifting, demand response potential, net emissions reductions, and so on. Those rate cases will also be burdened by uncertainty about how quickly the market for EVs will grow, and when and how the benefits of managed charging can be realized. It can seem much simpler, easier, and less risky for a utility to invest the same money in routine things like efficiency measures, where the business case for doing so is well established and understood and developing the rate case is a routine exercise.

SOLUTION

If the arrival of ubiquitous EVs (and ultimately SAEVs) is inevitable, then this is a matter of when (not if) regulators will offer an attractive case for utilities to make the investment. Performance-based regulation could be a good way to scale up utility investment in charging infrastructure, providing the incentives to bridge the gap between today's nascent market and tomorrow's large fleets of EVs with their reliable demand for chargers, while not exposing ratepayers to undue risk. (See sidebar on performance-based regulation on p.38.)

It will likely require regulatory leadership in order to overcome this obstacle, so regulators must be prepared to make the case to the public for widespread vehicle electrification before it is blindingly obvious that it is needed, and seize the opportunity to build charging infrastructure using all the tools at their disposal.

Several studies have shown that even before EVs constitute a large share of the total vehicle fleet, they can significantly increase the demand peak on the electricity system. For example, a 2013 study for the Vermont Energy Investment Corporation found that if 25% of vehicles were EVs and they were charged in an uncontrolled fashion, they could increase peak demand by 19%, requiring a significant investment in new generation, transmission, and distribution capacity. However, if that same load were spread out over the evening hours, the increase in peak demand could be cut to between zero and 6%. Further guiding charging to happen only at off-peak hours could avoid any increase at all in peak demand.[43] In order to make the most of ratepayer dollars, utilities should make investments in charging infrastructure and the capability to manage charging long before the market demands it. Indeed, as we detailed in our 2016 report *Electric Vehicles as Distributed Energy Resources*,[44] it is essential to have the requisite systems, programs, and tariffs in place before EVs arrive on the grid if utilities are to realize the full benefits of vehicle-grid integration that we summarized above.

In the longer term, EV charging represents one of the few opportunities that utilities have to increase electricity sales in an era in which load is generally flat to declining. If all light-duty vehicles in the U.S. were replaced with EVs, they would require about 1,000 TWh of additional electricity per year, or an increase of about 25% over our current electricity demand.[45] That's arguably the best growth opportunity that utilities now have. Once a significant number of EVs are on the road, utilities can explore their potential to provide ancillary services, and reduce system demand peaks and capital investment. But first they have to be positioned to capture the value of vehicle-grid integration.

COSTS ARE UNEVENLY DISTRIBUTED

An investment of the magnitude needed to materialize a fully electrified transportation regime in the United States would be very large—possibly on the order of that made in our road and water infrastructure during the New Deal and the post-World War II era. It would not be reasonable to expect private charging companies to be able to attract and invest that much capital on their own, particularly if it must be deployed at outsized risk initially, and then recovered over a long period of time through modest revenue streams. With the exception of Tesla, which is building a significant charging network to support the vehicles it makes, EV buyers and a few charging companies are making nearly all of the investment needed to keep vehicle electrification moving forward. Other deep-pocketed stakeholders in the EV-grid ecosystem, such as utilities and automakers other than Tesla, are arguably not bearing a fair and proportional share of the investment risk, but they stand to capture a significant share of the investment reward. Consequently, those who have borne the investment burden thus far are beginning to ask whether the cost of charging infrastructure has been, or will be, evenly distributed.

SOLUTION

Given that it is in pursuit of a universal public good, public spending seems both justified and reasonable in partnership with private capital and private companies. Rebates offered thus far (federal, state, municipal, and local) for vehicles and charging stations are helpful, but not sufficient. To accelerate the deployment of charging stations in order to meet the demand that new vehicles will entail, the public should make additional investment. That public investment would almost certainly include allowing utilities to take advantage of their very low cost of capital to extend their distribution networks and create make-ready locations for charging stations, along with associated upstream and locally related development of the power grid as demand grows. Depending on the view of the local regulatory authorities, it could also include allowing utilities to install and operate the stations. However, utility investment should be guided by smart performance-based regulations to ensure that the public receives a good value for its investment; see sidebar on performance-based regulation on p.38.

It would also be reasonable to allow public funding to extend to other enabling infrastructure, such as city or municipal funding, to help plan, locate, and construct charging-enabled parking spaces, or to offer tax relief to private investors in charging infrastructure. Municipal bond issuances, privately funded green bonds, infrastructure bank investments, and other investment vehicles to provide large-scale, patient capital could all play roles in the appropriate and fair distribution of investment burden and risk. Defining those specific arrangements is beyond the scope of this report, but we think it is proper and necessary that municipal planners engage with utilities and automakers, as well as with private charging companies, to creatively address this challenge.

IF YOU BUILD IT, THEY WILL COME.

Kansas City Power and Light (KCP&L) offers an instructive object lesson about how the availability of charging infrastructure can boost EV adoption.

In 2015, KCP&L decided to install over 1,000 EV charging stations to jump-start the EV charging station industry in Kansas City, Missouri, and capitalize on a new growth market for power—a rare opportunity in a time of flat-to-declining electricity demand.

Chuck Caisley, vice president of marketing and public affairs for KCP&L, explained the dilemma over how to approach the new market: "You're faced with a chicken-or-egg kind of thing. People won't get over range anxiety unless there are EV charging stations, and nobody around here is putting them up, because they don't think there's any demand."

The overwhelming majority of the new stations are Level 2 chargers purchased from ChargePoint and installed and operated by KCP&L. The Clean Charge Network is the first electric vehicle charging station network to be installed and operated by an investor-owned electric utility in the U.S. It is the largest network in the nation and has given Kansas City the largest number of chargers on a per-capita basis of any city in the U.S. KCP&L offers charging for free to drivers during the first two years of the network's operation.[46]

The results have been dramatic: Kansas City now leads the nation in EV growth, with EV adoption nearly doubling since the Clean Charge Network launched. "The sheer number of charging stations—strategically located where people live, work, and play—KCP&L's Clean Charge Network eliminated range anxiety in the Kansas City region," Caisley said.[47]

INVESTMENT IS INEQUITABLE

Some consumer advocates have argued that since EV charging infrastructure is currently only used by a small fraction of drivers, many of whom are wealthy enough to afford a more-expensive EV, allowing utilities to invest in EV charging infrastructure and recover the costs of those investments via charges that all customers pay amounts to an unfair shifting of costs from the wealthy onto all other customers, and therefore investments in charging infrastructure should be left to the private sector, which has to raise private capital and pay its own costs.

Although EVs are being rapidly adopted now, it's unlikely that they will become widespread until there is also widely available charging infrastructure sufficient to give consumers confidence that they can recharge their vehicles whenever they need to. And it is difficult for private charging companies to create a business case that would make it possible to finance and build additional public DCFC capacity, because utilization rates of existing DCFC are low, which is in turn a reflection of the small share of EVs in the personal vehicle market. Although individual Level 2 charging stations are not expensive, investments in them can be too slow to pay off to interest speculative commercial investors, at least until the market grows up and utilization rates improve.

The net result of this argument around inequitable investment is to delay the build-out of charging infrastructure, binding it to the chicken-and-egg problem that has been a hindrance to EV deployment all along.

SOLUTION

If one accepts our proposition that vehicle electrification is not only inevitable but also a net benefit to the public, given the many advantages of EVs over ICE vehicles, then the issue isn't about cost-shifting so much as it is about timing. When nearly all drivers have EVs, the cost of charging infrastructure will be appropriately distributed among them. Even nondrivers will benefit from the drastically reduced air pollutants of vehicle exhaust, and from the lower total cost of electrically powered mobility in general, which would put downward pressure on the price of all goods and services.

Therefore, the real question isn't about equity, but rather about who will provide the financing to build the infrastructure while the market matures, until all the costs and benefits can be shared equally. It is essentially a quotidian need for low-cost financing of perhaps 20 years' duration, at which point the utilization rate of the charging infrastructure should make a reasonable business case possible for owning and operating it, and drivers of all vehicle classes will be able to make use of it. Utilities could fill this need, but as we discuss in "Ownership" on p.39, that approach may work better in some states than others.

To the extent that regulators see a need to protect low-income and rural households from the shared costs of building charging infrastructure while the market matures, rebates or other cost-relief mechanisms should be preferred to avoiding any public investment whatsoever. That should no longer be considered a viable option.

THE CHARGING STATION NETWORK IS BALKANIZED

The existing network of charging stations developed in a bottom-up fashion through the independent efforts of numerous companies and governments. It was not designed in a top-down fashion and it was not planned for interoperability.

As a result, roaming across networks can be difficult for drivers, because the networks lack cooperative billing agreements and have not supported standards for executing transactions and settlements. Consequently, some EV drivers complain about having to carry a wallet full of payment cards for various charging station networks in order to travel long distances, and it can be difficult to implement managed charging, municipal incentive programs, or other projects across multiple networks. EV drivers who mainly commute over the same routes, or just drive around town, can work out a reliable payment solution that meets their needs. To be truly competitive with the ease of buying fuel for an ICE, however, the networks of EV chargers still need some integration work.

The current situation is analogous to traveling across interstate toll roads. While there is considerably more integration of these roads and their payment systems than there used to be, there are still some inconsistencies across regions that need to be ironed out in order to stitch together a fully integrated system from end to end and prepare for a future with longer-range EVs that drivers depend on to travel further.

SOLUTION

Charging network operators need to work together to develop cooperative billing arrangements. There are numerous protocols in various stages of development and implementation. However, the free, open source Open Charge Point Protocol (OCPP) has become the de facto open standard for charger-to-network communications in many countries, including in Europe and parts of the U.S. It supports interoperable information exchange about transactions and the operation of chargers.[48]

CHARGER DEPLOYMENT CONSIDERATIONS AND BEST PRACTICES

Having understood how to overcome the obstacles to charging station deployment, we can proceed to understanding where to site them.

The best type of charger to install in a given location depends on several variables that should be considered carefully for each location, such as:

- What kinds of vehicles are likely to visit the charger now and in the future?
- How depleted are the vehicles' batteries likely to be when they arrive, and how much of a charge will they need?
- How long is the vehicle likely to remain connected to the charger?
- What is the cost of providing charging service at that location?
- Who owns the charger and what is his or her business purpose for hosting or owning it?

Since the answers to these questions may vary significantly, and there is still very little data available to provide empirical evidence to prove one approach is better than another, we will not attempt to offer a one-size-fits-all answer, but rather identify some of the considerations that should go into siting an appropriate charger.

TABLE 2
TYPES OF CHARGERS

TYPE	VOLTAGE (V)	CAPACITY (KW)	MINUTES TO SUPPLY 80 MILES OF RANGE
LEVEL 1	120	1.4–1.9	630–860
LEVEL 2	240	3.4–20	60–350
DCFC (LEVEL3)[i]	480	50–400	3–24

DCFC ARE VERY DIFFERENT FROM LEVEL 1 AND LEVEL 2 CHARGERS

BEST PRACTICE IN BRIEF

- Level 2 chargers present the lowest-cost option to serve residential and workplace charging needs, and offer the best opportunity to manage EV charging for grid benefits.
- Though considerably more expensive, DCFC are necessary where vehicles need to charge quickly. These chargers will be essential to serve future mobility needs such as electrified public transit, fleets of ride-sharing vehicles, and autonomous vehicles.

[i] Level 3 chargers, which are more commonly known as DC fast chargers (DCFC), include three main types of connectors: CHAdeMO chargers, which have been popular in Asia and are increasingly being used in California and elsewhere; SAE Combined Charging Solution (aka SAE Combo or CCS); and the Tesla Supercharger format. Voltage may vary depending on the configuration.

LEVEL 1 CHARGERS

Because Level 1 charging (simply plugging the EV in to a standard 120V wall socket and using the vehicle's built-in converter) takes eight hours or more to charge up a fairly small-capacity EV battery, we don't expect Level 1 charging to play an important role in the future as EV battery packs get larger.

- In general, Level 1 charging does not require any new equipment, so it does not require any additional investment.
- Since Level 1 is a low-power type of charging, it would not present much of a challenge to grid operators, even if every house had an EV charging on a Level 1 charger—particularly if the charging were managed. But we believe that many households will prefer the speed and convenience of having a Level 2 charger.
- In theory, Level 1 chargers could be managed to provide dynamic grid services in the way we described in our 2016 report, *Electric Vehicles as Distributed Energy Resources*. However, at present, that would require a user to actively control the charging through the vehicle's on-board controls, which would require additional driver education and could be harder to achieve at scale. While some jurisdictions may elect to pursue customer education as a key strategy for managing Level 1 loads, others may wish to use time-varying rates or charging aggregators (see "Tariffs" on p.42).

LEVEL 2 CHARGERS

Level 2 chargers, which typically range from 3–20 kW in power output, are suitable for charging vehicles of any capacity overnight, or wherever EVs might be parked for several hours at a time, such as workplaces and shopping malls.

- Level 2 chargers have relatively low capital costs (around $600 for a residential unit, plus installation costs),[50] so they can be deployed in numbers for a modest investment, and the business case for owning one doesn't depend heavily on its utilization rate. These attributes make Level 2 chargers a good choice for many types of installations.
- Level 2 chargers are the low-cost, reasonably fast-charging option. They do not typically draw enough power to incur demand charges (unless there are several of them on a single meter), which helps to keep the cost of owning or operating one low. Of course, there are always exceptions and uncommon use-cases do happen; for such instances, appropriate rate design may be the best course of action (see "Tariffs" on p.42).
- Level 2 charger loads are generally within the range of normal residential and workplace service capacity. Even a high-end, high-speed, residential charging station, the 50A "wall connector" from Tesla, would draw a maximum of 12 kW of power, which is well within the 48 kW capacity of a typical modern 200A residential main service panel.[51] However, when Level 2 chargers are used in a cluster (such as in a neighborhood where several EVs are charging at once and drawing their power from a single transformer, or in a workplace parking lot with many charging ports), they may require the utility to upgrade distribution grid equipment.
- Level 2 chargers are the best option for using managed charging to provide dynamic grid services. This makes them an essential resource in a widely available and distributed charging network. They are also more efficient than Level 1 chargers, so making it possible for drivers to switch from Level 1 to Level 2 will help reduce the overall EV charging load.

DCFC

DCFC are useful where vehicles need a substantial charge in a fairly short period of time (usually measured in minutes). This capability comes with some important attributes, which must be taken into consideration:

- DCFC are expensive to install. The high capital cost of DCFC (typically on the order of $50,000 each,[52] though they can cost considerably more, depending on the installation), means that it's important to site them where they will have high utilization rates and generate enough revenue to cover their costs.

- DCFC can be expensive to operate. Being able to deliver a lot of energy in a short period of time generally means that they will also draw a lot of power from the grid, and that can mean high costs for providing the charging service. The type of utility tariff that a DCFC is on can drastically affect the cost of owning and operating a DCFC, as we demonstrated in our April 2017 report, *EVgo Fleet and Tariff Analysis*.[53] In one example, a charger in San Diego Gas and Electric (SDG&E) territory cost $3,114 a month under its existing tariff, but just $138 a month under a new tariff SDG&E proposed for DCFC. A sustainable DCFC is a profitable DCFC, and a profitable DCFC will have high utilization, or be on a tariff with limited demand charges, or both.
- Today's DCFC can deliver around 50–140 kW of power, which can mean fairly expensive make-ready infrastructure, especially if they are installed as a cluster on a single distribution circuit. But ChargePoint has already announced a 400 kW charger that it expects to start shipping in 2017, and other higher-capacity chargers are likely to be installed over the coming years, especially for supporting electric mass-transit vehicles. Deploying these new high-capacity chargers will come with substantially increased costs for grid connection and power delivery over the utility distribution network. Clusters of new, high-powered DCFC with high utilization rates will also have uncertain effects on the distribution grid. Siting these chargers optimally—again, especially if they are clustered—will be a nontrivial exercise calling for careful collaboration between utilities, city planners, and site hosts, and for thoughtful and proactive management on the part of distribution grid operators.
- Under the typical use-case, DCFC are not useful as dynamic loads. Users expect to be able to obtain a maximum-speed charge from them in the shortest possible time, so it's generally not practical to turn DCFC on and off (or ramp their power output) in response to changing grid conditions. However, some charging station operators are beginning to pair DCFC installations with on-site battery banks to supply power to the charging stations and avoid demand charges. These battery banks could also be used to respond to grid conditions and provide grid services. If it becomes commonplace to site grid-interactive storage systems with DCFC charging installations, then they, too, could become useful as dynamic loads. DCFC loads could also be more dynamic if DCFC operators were to expose customers to time-varying retail pricing that reflects their time-varying wholesale electricity costs. (See the Appendix for details on the methodology of our site-host cost analysis.)

It's too soon to tell what the right mix of chargers will be; the answers will vary from place to place; and which mix is best will change over time as vehicles become more advanced. However, it's safe to say that a widely available charging network will require a mix of Level 2 and DCFC, and so deployment plans should include both. Several utilities report that customers tend to rely on Level 1 or 2 charging at home for the majority of their commuting needs, then call on public DCFC stations for long-distance trips or for a quick top-off while running a day's errands. This use pattern suggests that TOU rate design could be an effective way to manage charging loads, if drivers are exposed to time-varying retail costs.

THE IMPACT OF "DIESELGATE"

Under the terms of its settlement with the California Air Resources Board, the Volkswagen-funded Electrify America program will invest $2 billion over the next 10 years in zero emission-vehicle infrastructure and education programs in the U.S., of which $800 million will be invested in California and $1.2 billion will be invested in the rest of the states. Although the National ZEV Investment Plan is still in development, we estimate that the first of four 30-month, $300 million investment cycles could result in about a 50% increase over the number of DCFC charging ports that exist nationally today, as well as a slight increase in the number of Level 2 chargers. If the final three investment cycles were similar to the first cycle, the total number of DCFC charging ports nationally could be double the roughly 5,700 ports that exist currently.

The power of this new DCFC infrastructure will be significantly greater than the existing DCFC, however. Most existing, nonproprietary DCFC chargers deliver 25–50 kW of power, and Tesla's proprietary Superchargers currently deliver up to 120 kW. The new DCFC units deployed under the Electrify America investment will be able to deliver 150 kW or 320 kW of power, depending on the model, with the intention of upgrading all of the units to 320 kW capacity by the end of the 10-year investment cycle. Therefore, whereas the first 30-month investment cycle of the Electrify America plan could deliver a 50% increase in the number of DCFC charging ports nationally, their ability to deliver power could double the existing capacity. Regulators should ensure that they have accurate estimates of the additional demand these chargers will put on utility grids, and that they are employing measures to reduce the overall impact on the cost of service.

Although there are no cars that can take a charge at a 320 kW rate today, future vehicles are expected to be able to tolerate much higher rates of charging. Theoretically, a 320 kW charger could deliver 19 miles of range per minute of charging—enough to give a full charge to a 2017 Chevy Bolt, with 238 miles of range, in perhaps 13 minutes. Until vehicles can actually take such high rates of charge, however, both vehicles and chargers can still use these newer ultra-high-speed chargers at an appropriate throttled speed, as controlled by the vehicles.

Since the Volkswagen emissions-cheating scandal broke, other manufacturers including Fiat Chrysler, General Motors, Daimler, Audi, Renault, PSA Group (the maker of Peugeot and Citroen cars), Porsche, and Bosch have all been accused of similar cheating activities.[54] If those companies were found guilty and forced to make investments in EV charging infrastructure as Volkswagen was, it could result in a very significant increase in the number of available charging stations much sooner than most observers expect.

Although the Electrify America investment will result in a significant increase in the number and power of charging stations, increasing EV penetration will demand even greater growth in charging infrastructure. In 2030, three years after the final Electrify America investment cycle is complete, Navigant forecasts that 10 million EVs will be sold annually,[55] while Bloomberg New Energy Finance estimates just under 5 million units,[56] and the U.S. Energy Information Administration (EIA) just over 1 million.[57] If any of those forecasts turn out to be accurate, we estimate that EV charging infrastructure must increase by a factor of 10–100 just to meet the needs of the EVs sold in 2030, let alone the EVs that already existed prior to 2030.

An increase in charging stations of this magnitude underscores how important it will be for municipal planners, property owners, utilities, and regulators to actively engage now with installers of charging stations to ensure that they are located in such a way that they can be used effectively as grid assets, as we described in our 2016 report, *Electric Vehicles as Distributed Energy Resources*.[58] If these new charging stations are not installed with sufficient forethought about how and when they will be used, they could have numerous negative repercussions on electricity grids instead of positive ones, and might not be used frequently enough to enable a profitable business model for charging station operators.

SITING CONSIDERATIONS

BEST PRACTICE IN BRIEF

- Public charging stations should be sited for high utilization.
- Level 2 chargers should be sited where drivers have a preference to charge over a longer interval (i.e., several hours), such as workplaces and residences.
- DCFC should be sited where utilization will be high and their grid impact will be low.
- Hubs that provide a combination of Level 2 chargers and DCFC are likely to be the best way to serve public fleets, transportation network carriers, and autonomous vehicles.

Public charging stations must be sited where they will be used frequently. A high utilization rate is important not only so that chargers can serve a large number of vehicles, but also so that they can earn enough revenue to support a profitable business case and justify the investment made in them. Currently, due to the relatively low number of EVs on the road, most DCFC public charging stations have relatively low utilization rates (in use 15% or less of the time). But in the future, it will be important to increase DCFC utilization rates in order to have a profitable and sustainable network, especially if the utility tariffs those DCFC are under are similar to the tariffs most of them are under today. As we explain below, rate design reform can make it possible for chargers with low utilization rates to be profitable as well.

To site public chargers where they will be used most, planners should look for suitable sites along high-traffic corridors, in shopping centers, at grocery stores, and other such locations. Important siting considerations include the distance between charging stations, the likely dwell time of vehicles at each station, and how convenient it is for drivers to access the stations. Our analysis of EVgo's fleet of charging stations,[59] and usage patterns in some urban municipalities, suggest the following best practices for siting.

- High-traffic retail areas can support a mix of Level 2 and DCFC stations.
- Commuting corridors, highways, taxi and ridesharing depots, and locations that may experience urgent needs for charging would be best served by DCFC.
- Wherever there is, or could be, a fleet of at least 50 high-ridesharing vehicles, charging depots may be appropriate. A typical charging depot might feature one Level 2 charger for every two vehicles, or one DCFC for every 8–10 vehicles, depending on vehicle utilization and driving patterns.

Before embarking on a significant charging station deployment, community planners are advised to study expected usage patterns with these criteria in mind, and ensure that most chargers are installed where they will be well used. Planners would also benefit from having access to data on the usage of existing charging stations, and here, regulators may have a role to play in providing that access. Pilot projects can be a good way to gather usage data and understand what the market needs in specific locations.

However, like a gas station in the middle of nowhere, it is also unavoidable that some charging stations will need to be installed where utilization is likely to be low, but critical—such as emergency use locations, and sites at the extremities of a network. A complete network, even if some stations are underused, is essential to supporting a highly electrified vehicle fleet. Leaving the siting of charging stations entirely up to the market is unlikely to produce a complete network.

Exhibit JRB-5

A NO-REGRETS PATH TO SAEV

Although fully autonomous vehicles are not yet permitted to operate, their advantages over POVs suggest that the SAEV future will certainly arrive, for reasons we explained in our 2016 report, *Peak Car Ownership*.[60] Those siting chargers must take that eventuality into account, in order to avoid building charging infrastructure for POVs that will be stranded when the SAEV future arrives.

Based on our own analysis and the perspectives of the experts we interviewed for this report, we believe the best, no-regrets path to deploying chargers will be to install Level 2 chargers where practicable and at a reasonable cost in private homes and workplaces (where vehicles will have longer dwell times), and DCFC in high-traffic shopping areas, commuting corridors, and long-distance highway stops (where dwell times will be short). When they arrive, SAEV fleets are likely to have high-capacity battery packs enabling them to run for 200 miles or more on a charge. The lowest-cost way to support those fleets would be, first, to have them fully charge up (receiving perhaps 60–80 kWh) on a daily basis, primarily using Level 2 chargers at purpose-built charging depots designed to provide high-capacity electric service at a low cost. Then, the fleets would get a modest boost (perhaps on the order of 10 kWh or less) as needed from the distributed network of DCFC as the vehicles make their rounds over the course of the day. With this strategy, only the home and workplace Level 2 chargers would be potentially at risk of becoming stranded assets a decade or more from now, but their cost ($580 each per year today,[61] and probably significantly less in the future) is low enough that this would not be enough of a risk to dissuade their deployment in the meantime.

PERFORMANCE-BASED INCENTIVES TO DRIVE DOWN CHARGING INFRASTRUCTURE COSTS

Where the regulatory environment is open to utility investment in charging station infrastructure, regulators may want to consider the best ways to encourage that investment, and where to draw the line between utility and private-sector investment.

While not a comprehensive list by any means, here are some ideas that may stimulate creative approaches to targeted performance-based incentives for each type of infrastructure that are designed to drive down the total cost of the infrastructure to society over time.

MAKE-READY INFRASTRUCTURE

Allow utilities to install make-ready infrastructure and add it to their rate base, but with a lower guaranteed rate of return (as statutes allow), plus a bonus for building make-ready locations that host chargers with high utilization rates. The bonus could increase with the utilization rate, irrespective of who actually owns and operates the charging station.

LEVEL 2 CHARGERS

Require utilities that want to own Level 2 charging stations to offer a series of competitive solicitations for successive tranches of charging stations. Each solicitation could have a price cap per station, which declines with each new solicitation. Or the utility could be permitted to finance and build the stations itself, but only if it could underbid the lowest bids received in response to its requests for proposals.

DCFC

Because DCFC are expensive, and it could take time for the market to mature and utilization rates to rise to the point where an attractive business case exists for private-sector charging companies, utilities could be permitted to build, own, and operate public DCFC, but only earn a rate of return if the stations obtain a specified utilization rate that rises over time. Such a structure would probably be designed around a fixed time frame in order to give utilities enough visibility to make the investment, and enough time to allow the market to mature, while also capping the total return on a station over time.

ANY UTILITY INVESTMENT

Shift some or all of the cost recovery for a utility investment into the volumetric rate (the charge for energy delivered through the charging station), so that in order to recover the capital investment and potentially earn additional income, the charging stations have to be well used. To ensure utility interest in this approach, the volumetric rate premium could start at a high level and then decline over time, to create an incentive to sell more energy through the charging station as the market matures and demand scales up.

OWNERSHIP

BEST PRACTICE IN BRIEF

- There remains too little data to unequivocally say one ownership model is better than another.
- Where states and municipalities have limited experience and limited data, they should use pilots and demonstrations to test multiple ownership options, but should not delay in launching these tests.
- States and regulatory bodies should both seek to test different models, as well as collaboratively engage relevant stakeholders (such as utilities, municipalities, and charging network operators) before making long-lasting decisions.
- Allow for future flexibility, as the ownership model that is most appropriate while the market is young and small may not be the best model for a mature EV market.

The question of who should own charging stations has no simple or universal answer. Since the deployment and operation of charging stations can fall under state authority as a form of public utility, it will be up to each of our 50 states—our “laboratories of democracy”—to decide which approach is best for them. We see pros and cons with each approach, and believe that the regulatory environment in each state is potentially a key factor in choosing a path.

At a minimum, most legislative and regulatory bodies seem to agree that utilities should be permitted to build and own make-ready locations (i.e., power supplied to the point where a charging station might be installed), and to recover those investments via the rate base as a general social good. As we noted above, the public benefits that can come from vehicle electrification are numerous, including reducing pollutant emissions that are harmful to human health, reducing the overall cost of mobility, and even reducing the cost of grid power if vehicle-grid integration is done in such a way that it optimizes the entire grid.

Further, extending the grid to make-ready locations would be entirely in keeping with the long-established principle of line extension, in which all customers pay for extending the distribution grid, including new service for rural customers where the cost of providing that service is far greater than that for customers living in densely populated urban environments. By this reasoning, an extension of the distribution grid is not justified by a cost-benefit analysis for a specific customer or group of customers. Rather, the value of the entire network is considered to be shared by all customers. The same kind of reasoning allowed telephone companies to build out the pay telephone network. Each phone wasn't necessarily expected to turn a profit, but was considered necessary in order for the entire network to be functional and accessible.

Allowing utilities to also install and own charging stations could be the fastest way to build them, since utilities have access to large amounts of very low-cost capital and the ability to recover investments over decades. This may also be the easiest path in fully regulated electricity markets, where it would be routine to recover investments in the charging infrastructure through the rate base. It could also serve as insurance against price gouging by private sector companies.

Conversely, regulators must also be careful to avoid creating a situation where a utility can leverage its low internal cost of power generation and delivery to undercut private sector competitors on retail charging prices. Full utility ownership could stifle a competitive private sector market in charging stations, and utility deployments might not be as innovative in terms of technology or business model design as the private sector would likely produce. Regulators who do allow utility ownership of charging stations should take care to preserve some opportunity for private sector companies, or ensure that there is an opportunity for private companies to re-enter the business once it matures and there is a better business case for nonutility owners.

Dedicating the charging station market to the private sector only, and disallowing utility ownership of anything beyond a make-ready point, would likely yield the usual advantages of a competitive market, such as lower cost over time, and more rapid technological and business model innovation. Leaving charging station investment to the private sector would probably be the easiest path in largely deregulated states. However, the private sector may not be able to deploy charging stations at the speed required by the growth of vehicles, due to the need for large amounts of patient capital and the lack of a guaranteed demand for charging stations until the EV market matures.

The experience of California is instructive on this point. The California Public Utilities Commission (CPUC) originally found that "the benefits of utility ownership of EVSE [electric vehicle supply equipment, i.e., charging stations] did not outweigh the competitive limitation that may result from utility ownership," and disallowed utility ownership, reserving the vehicle charging market for the private sector.[62] When the deployment of charging stations by the private sector proved to be too slow to meet the state's objectives, the CPUC then removed the blanket prohibition on utility ownership of charging infrastructure in favor of an "interim approach" which uses a "balancing test that weighs the benefits of electric utility ownership of charging infrastructure against the potential competitive limitation…on a case-specific basis."[63] That decision permits third-party providers to offer charging products to the marketplace.

Instead of viewing the gap between deploying charging stations and their eventual full utilization as an argument against deployment because of the risk of cost-shifting in the short term, we view it as an indication that regulators, utilities, and charging station providers should work together to seek a more profitable business opportunity for private charging companies sooner than might otherwise materialize, and to ensure that adequate patient capital can participate in the deployment.

As we describe in "Different Strokes" on p.46, the regulatory environment in a state can be a key factor in the business opportunity for charging station operators. Some jurisdictions allow utilities to own charging infrastructure, and some don't. In some areas, charging station operators may resell electricity to end-users, and use a markup on the electricity they sell to improve their overall economics. In other areas, such as where a distribution utility has sole authority to sell electricity, they may not resell electricity, and so they may be restricted to charging customers on a per-use basis, or another arrangement (such as bundling "free" charging into a parking space rental). Regulators and municipal officials should consider the restrictions that apply in their areas, and whether the business opportunity exists to support private-sector charging station providers.

PENETRATION

BEST PRACTICE IN BRIEF

- There is currently too little data to indicate what the best ratio of charging stations to electric vehicles is.
- In the absence of evidence, collect and share data about infrastructure utilization early and often.
- Give special attention to sites that provide charging services to meet unique needs, such as transit corridors and multifamily dwellings.

A final important consideration for transportation planners is the extent and timing of charging station deployments.

Ultimately, major municipalities should plan to have charging capacity at a charging depot for every high-usage service vehicle in is territory. Because they have many charging stations at a single site, charging depots have economies of scale and will be the lowest-cost, highest-efficiency way to charge fleets of vehicles used for city services, ridesharing services, delivery services, and the like. The specific numbers and types of charging stations needed will depend on the usage patterns and numbers of vehicles in those fleets.

In most cases, it is probably best if nearly all households and workplaces have a Level 2 charging station, if they have garages or carports that can accommodate one, or that they use Level 1 charging when parked there. These low-speed charging loads are relatively straightforward for utilities to accommodate, and they offer the greatest opportunity for managed charging to provide grid services to utilities. Ideally, Level 1 and Level 2 charging would meet a large share (perhaps 80% or more) of the total charging demand for personally owned vehicles.

The number of public DCFC needed should be determined from the number of vehicles likely to visit a retail center or commuting corridor. As a first approximation, a low-risk way to approach this question is to calculate how many DCFC in a given location could sustain a 50% utilization rate within a feasible investment horizon. For example, if a city believes that it will have enough EVs circulating through its downtown area such that DCFC in that area could be in use 50% of the time within the next ten years, it should probably begin to deploy those DCFC now.

Multiunit dwellings present a special set of challenges for charging infrastructure, which may include a mixture of Level 1, Level 2, and DCFC charging stations, depending on the unique attributes of a given building and its residents. Detailing those factors is beyond the scope of this paper, but the State of California has several reports and resources offering useful guidance.[64]

Although it's hard to generalize, given the wide variance from place to place, charging station deployments appear to be lagging behind EV growth. A recent analysis by Bloomberg New Energy Finance asserts that more public chargers are needed,[65] despite an increase in deployments over the past five years; that a lack of home charging will restrict sales once EVs reach cost parity with ICE vehicles; and that the U.S. will hit an "infrastructure cap" in the mid-2030s due to a lack of charging stations, causing EV sales growth to slow significantly. To avoid this unfortunate circumstance and keep the EV revolution going, we'll need to install chargers faster.

TARIFFS

BEST PRACTICE IN BRIEF

- Create dedicated tariffs for EV chargers because their demands will be different from that of a household or business, and can be controlled separately and more flexibly than those loads.
- Slow and fast chargers require different tariffs in order to optimize utilization, charging station economics, and grid impacts.
- All EV tariffs should feature some level of time-variance or dynamic pricing in order to optimize charging patterns for grid services and reduced grid impacts.
- DCFC chargers should be on tariffs with reduced, delayed, or no demand charges until the market matures and utilization rates are high enough that demand charges constitute a normal portion of monthly bills (e.g., 30%, not 90%).
- Consider creating specific tariffs for DCFC to promote a strong and sustainable business case for owning and operating them.

It's important for utilities to offer appropriate tariffs for EV charging before significant numbers of EVs appear on their grids, because once EV drivers acquire a habit of charging at a particular time and place, those habits can be hard to break. This was a key finding of an EV tariff pricing study conducted for San Diego Gas & Electric.[66] With EVs now set to arrive in significant numbers, it is critical that utilities and regulators ensure that they have tariffs at the ready that will guide charging toward the valleys of system load profiles and off the peaks, and that will enable a healthy ecosystem of charging stations.

Field experience to date indicates that the optimal tariffs for EV charging employ a time-of-use design, and are usually dedicated to EV charging only, because these tariffs offer the maximal opportunity to shift charging to the off-peak periods and provide the greatest grid benefit and the lowest cost of charging.[67,68] Additionally, we believe these tariffs should offer lower prices for Level 1 and Level 2 charging than for DCFC, because the cost of providing service for Level 1 and Level 2 chargers is lower, and because they are more easily managed to deliver grid services.

Time-varying tariffs are a simple, passive way to implement managed charging. Good price signals, if well designed, should be able to produce the desired load shape without impeding a vehicle owner's control over vehicle charging. Active management techniques, such as allowing utilities or aggregator companies such as eMotorWerks to directly control chargers to provide grid services, may also play more of a role in the future. However, field experience using active management is still fairly limited.

DEDICATED TARIFFS FOR EV CHARGING

The load profile of a Level 2 charger should be very different than that of a typical household or business where it is hosted, because the charger should be actively managed to encourage, or drivers should be offered an incentive to encourage, charging during the off-peak hours of the local grid. For example, a business may find that a commercial tariff with a flat rate for electricity is best for its general, nondiscretionary loads, but that Level 2 charging stations provided for customers and employees should be on a TOU tariff that features a large differential between on- and off-peak rates, to encourage discretionary charging when the cost of generating power is lowest. To enable this, many utilities require that a charging station be connected through a dedicated meter, separate from other loads at the site, although this does incur additional cost.

DIFFERENT RATES FOR SLOW AND FAST CHARGERS

In order to guide charging as much as possible toward low-cost, low-speed, Level 1 and Level 2 charging, which can help reduce overall system costs and offer the best opportunity for managed charging, we believe that customers should be able to use those chargers at a much lower cost than public DCFC charging. In practice, non-dedicated, public DCFC charging is generally more expensive than Level 1 or Level 2 charging already, but that appears to be an artifact of the way that charging stations and the tariffs they're under evolved, and not an explicit outcome that regulators and utilities sought. But we believe it should be. Retail public DCFC charging should be relatively expensive, to reflect the much higher capital cost of installing DCFC and the higher cost of providing electricity to those stations, and Level 1 or Level 2 charging should be significantly cheaper, to reduce the driver's cost of fueling and enable the use of flexible, low-cost infrastructure that can be managed to deliver grid services.

TIME-VARYING RATES AND DYNAMIC PRICING

As we discussed in detail in our 2016 report *Electric Vehicles As Distributed Energy Resources*,[69] experience in several significant test projects shows that TOU rates are effective at shifting loads to off-peak periods, and that the greater the price differential between on- and off-peak periods, the greater the shift. Results from a joint research project between The EV Project and SDG&E found that a price ratio of 2:1 was sufficient to shift 78% of all charging to the super off-peak period, while a ratio of 6:1 shifted 85% of all charging to the super off-peak period.[70]

Dynamic rates may be even more effective than TOU rates at matching a charging station's demand for power with the utility's cost of providing that power at a specific point in time. A pilot program being conducted by SDG&E called "Power Your Drive" will use such an approach, based on a dedicated EV tariff that will feature hourly dynamic prices reflecting grid conditions.[71] The prices will be published a day ahead and posted on a publicly available website, which will also include a database of the most recent hourly prices that reflect both system and circuit conditions, and include a circuit-level map of current hourly prices on all participating circuits. Customers will be able to use the website or a smartphone app to enter their preferences for charging durations and times, including the maximum price they're willing to pay. Then the app will match those preferences with the price information in order to provide the customer low-cost electric fuel based on their preferences and the hourly day-ahead prices. The Power Your Drive program is still getting under way and has not yielded any data yet, but regulators and utilities in other states would be wise to look carefully at its results when they are available, and determine if a similar program might be effective in their territories.

REDUCED OR NO DEMAND CHARGES FOR PUBLIC DCFC

Until the market for EVs matures such that public DCFC experience substantially higher utilization rates, it may be necessary for utilities to offer special tariffs, or variations on existing tariffs, that are more conducive to profitable DCFC ownership than are conventional commercial and industrial tariffs.

In our 2017 report *EVgo Fleet and Tariff Analysis*,[72] we examined every charging session in 2016 on all 230 of charging-infrastructure provider EVgo's 50-kW DCFC stations in California. The study showed that where a charger's utilization rate is low, demand charges can be responsible for over 90% of its electricity costs, depending on the tariff. That analysis showed that demand charges, more than other rate components, are the primary reason why it is economically challenging to operate public DCFC profitably in California, while utilization rates are still low. Until the market matures and utilization rates climb to the point where conventional demand charges would make up a more reasonable portion of the utility bill, it makes sense to deemphasize their role in the tariff.

This is the approach that Southern California Edison (SCE) has taken in its most recent proposed tariffs for EVs. SCE's new EV tariffs would suspend monthly demand charges during a five-year introductory period and recover more costs through energy charges, and then phase in demand charges for a five-year intermediate period. As the demand charges increase, the energy charges will decrease. During this intermediate period, the demand charges would collect an increasing share of distribution capacity-related costs, up to 60%, while the remaining 40% of distribution capacity costs would be collected via TOU energy charges. At that point, SCE claims that the demand charges will "still be lower than what new EV customers would pay on their otherwise applicable (non-EV) commercial rates today."[73]

Similarly, the new Public Charging GIR tariff proposed by San Diego Gas & Electric (SDG&E) for public chargers eliminates the grid integration charge (a type of demand charge) and recovers more costs through "dynamic adders" which are incurred for demand that occurs coincident with the top system hours of the year for a given circuit. This approach would be more likely to reflect the actual costs of providing service during high-demand hours, and less likely to trigger costly demand charges regardless of when the demand occurred. It would also offer the opportunity for a DCFC operator to avoid the peak hours, or switch to on-site storage to provide the power, or try some other means of avoiding the charges.

Both the SCE and SDG&E proposed tariffs would substantially improve the economics of operating a public DCFC, while still allowing the utility to recover costs adequately, being consistent with good rate-design principles, and helping to achieve the societal objective of widespread vehicle electrification.

As next-generation fast-charging stations featuring 150 kW and higher rates of charging begin to be deployed this year, the proper role of demand charges and the question of appropriate rate design will become even more important. Tariffs should reflect the actual cost of providing service, and should charge more for coincident peak demand. A charging depot with just six 150 kW DCFC, or two 450 kW DCFC, would be able to generate a power draw equivalent to the power demand of a large high-rise office building, which would impose nontrivial demands on the system and a significant cost of providing service. On the other hand, it's also important to give the market for high-powered public DCFC time to mature. Indeed, as we have asserted in this report, it's probably best to build charging infrastructure before there is high demand for it, to allow time for learning how to shape the demand for best effect. That approach would implicitly mean operating DCFC before they are able to afford conventional demand charges.

In short: demand charges are a blunt instrument for aligning costs with uses. They should not be ruled out, especially where DCFC are likely to bring very large new loads onto utility systems. But neither should they be a default characteristic of public DCFC rate design, being blindly triggered by rare charging events that might not even incur additional system costs because they are not coincident with system demand peaks. Rate design approaches such as scaling up demand charges over time, shifting some cost recovery to volumetric charges initially, and using dynamic adders to recover the cost of providing service during system peaks should all be considered in addition to demand charges, as utilities and regulators seek to accommodate the novel loads of public DCFC.

RATE DESIGN FOR SUSTAINABLE DCFC BUSINESSES

Electricity tariffs designed to create a sustainable business case for owning DCFC would have the following characteristics:

- Time-varying volumetric rates for electricity, such as a TOU rate. Ideally, these volumetric charges would recover all, or nearly all, of the cost of providing energy and system capacity. The highest-cost periods of the TOU tariff should coincide with the periods of highest system demand (or congestion) to the maximum practical degree of granularity.
- Low fixed charges, which primarily reflect routine costs for things like maintenance and billing.
- The opportunity for site hosts or charging station aggregators to earn credit for providing grid services such as demand response.
- Rates that vary by location. For example, a utility could offer low rates for DCFC installed in overbuilt and underutilized areas of the grid, in order to increase the efficiency of existing infrastructure and build new EV charging infrastructure at low cost.
- Limited or no demand charges, at least until charging stations reach significant utilization rates. Where demand charges are deemed to be necessary, it is essential that they be designed to recover only location-specific costs of connection to the grid, not upstream costs of distribution circuits, transmission, or generation. Generally, demand charges should reflect demand spikes that are coincident with system load peaks.
- Critical peak pricing can help recover the cost of meeting a charging station's peak demand without unduly burdening a charging station with a low utilization rate, and without shifting costs from EV drivers to all ratepayers.

Our analysis shows that while utilization rates are low, reducing or eliminating demand charges for the commercial public DCFC market is consistent with good rate-design principles and helps to achieve the societal objective of widespread vehicle electrification.[74] Recovering nearly all utility costs for generation, transmission, and distribution through volumetric rates is appropriate for tariffs that apply to public DCFC. Other approaches to rate design, in which cost components scale with usage rather than being based on the demand peak in a month, can be appropriate ways to recover costs without stifling a nascent market. For example, as the utilization rate of a DCFC increases, a utility could reduce the volumetric rate and increase the demand charge.

For more of RMI's original research and analysis on tariffs and rate design, please see our reports *Rate Design for the Distribution Edge* (2014)[75] and *A Review of Alternative Rate Designs* (2016).[76]

Exhibit JRB-5

DIFFERENT STROKES

The path that a given utility or state might take into vehicle electrification will vary according to different configurations of several fundamental factors.

For example, the regulatory environment takes several forms in U.S. states, and can be quite nuanced, affecting how investments in chargers can be made, how chargers are used, and what the business opportunity is for third-party charger providers. For example, the California PUC does not assert jurisdiction over third-party charger providers offering charging services, but it does require Southern California Edison (SCE) to force third-party site hosts who own and operate chargers using SCE's make-ready infrastructure to follow certain standards and requirements.[77] The Missouri Public Service Commission ruled in April 2017 that it did not have jurisdiction over chargers at all, arguing that chargers are equivalent to smart phone charging stations or kiosks, or electricity hookups at RV parks, and that "the charging service is the product being sold, not the electricity used to power the charging system."[78] The Massachusetts Department of Public Utilities ruled similarly in August, 2014. And the New York Public

FIGURE 10

RELATIVE PUBLIC-CHARGER DISTRIBUTION BY CHARGER TYPE

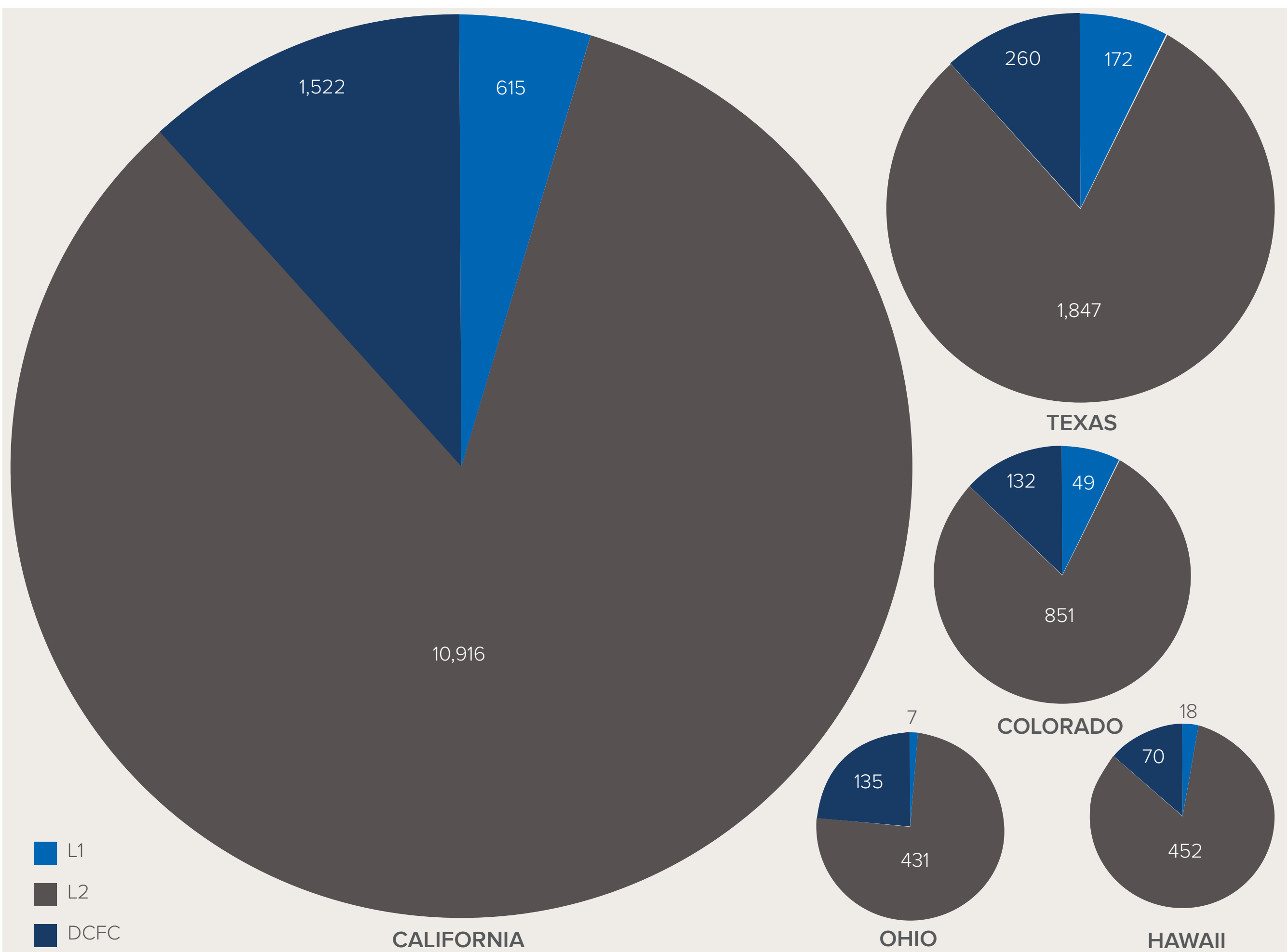


TABLE 3

EV AND EVSE DEPLOYMENT STATISTICS BY STATE[80]

	EV PENETRATION	EVS ON THE ROAD	NUMBER OF EVS PER L2 CHARGER	NUMBER OF EVS PER DCFC
CALIFORNIA	2.10%	299,038	27	196
HAWAII	1.20%	6,178	14	88
COLORADO	0.56%	10,033	12	76
TEXAS	0.23%	18,930	10	73
OHIO	0.15%	6,973	16	52

Service Commission ruled in November 2013 that it did not have jurisdiction over public chargers, their owners and operators, or transactions between them, if they did not meet the law's definition of "electric corporation."[79] This is just one factor that can determine which paths to deployment are best in each state.

Each state will also have to determine for itself how to ensure that its charging network will be adequate to meet demand, deployed at a reasonable cost, and that it will be neither deployed too early nor too late. Each state may also need to determine ways to limit the retail cost of charging, and to limit the cost of owning and operating charging stations, in order to ensure a vigorous market. On these questions, there is a natural tension between what is best done via top-down planning by a central authority, and what is best done by letting a market seek the right solutions, and there are no one-size-fits-all answers.

To demonstrate the different paths that result from various combinations of these factors, we look at five U.S. states as exemplars: California, Colorado, Hawaii, Ohio, and Texas. We present an overview of the current state of charging station deployment in these states, along with the economics of EV ownership and charging station use from different stakeholder perspectives.

We begin with a look at EV penetration for each state (Table 3). Interestingly, California has the highest EV penetration in the U.S. while also having the highest number of EVs per charger. For example, there is one DCFC per 196 EVs and one Level 2 charger per 27 EVs in California, while in Texas there are nearly three times the number of DCFCs and twice the number of Level 2 chargers per registered EV. We also note that Hawaii, Colorado, Texas, and Ohio all have very similar ratios of EVs to charging stations, from about 1% in Hawaii to about 0.15% in Ohio. This suggests that where EV growth is strongest, charger deployment is lagging EV adoption. It is unclear at this early stage of EV adoption what the ideal ratio of public charging stations to EVs is, however.

These results suggest that California is moving ahead with EV adoption while utilities, regulators, and charging station companies are tied up in the debate around ownership models, siting, and tariff design, and thus impeding the charging station growth that will be needed to meet demand. This could make it more difficult for California to capture the full value EVs bring to the grid—particularly the value from managed charging.

For each of our exemplar states, we then compare the cost per mile for fueling an ICE vehicle to the cost of charging EVs under five different charging options:

- Uncontrolled charging at home on a Level 2 charger under a flat electricity rate
- At home on a Level 2 charger under a TOU rate with 95% of charging occurring at non-peak times
- At work on a Level 2 charger
- On a public DCFC network
- As a commercial fleet charging at a centralized charging depot

This analysis considers the different tariffs available for home, work, and commercial public charging based on the customer class and the typical load profile of each type of site.

FIGURE 11

RETAIL COST TO EV OWNER, OR EMPLOYER OF EV OWNER, TO CHARGE ONE MILE OF EV RANGE UNDER DIFFERENT UTILITY TARIFFS AND DCFC PROGRAMS

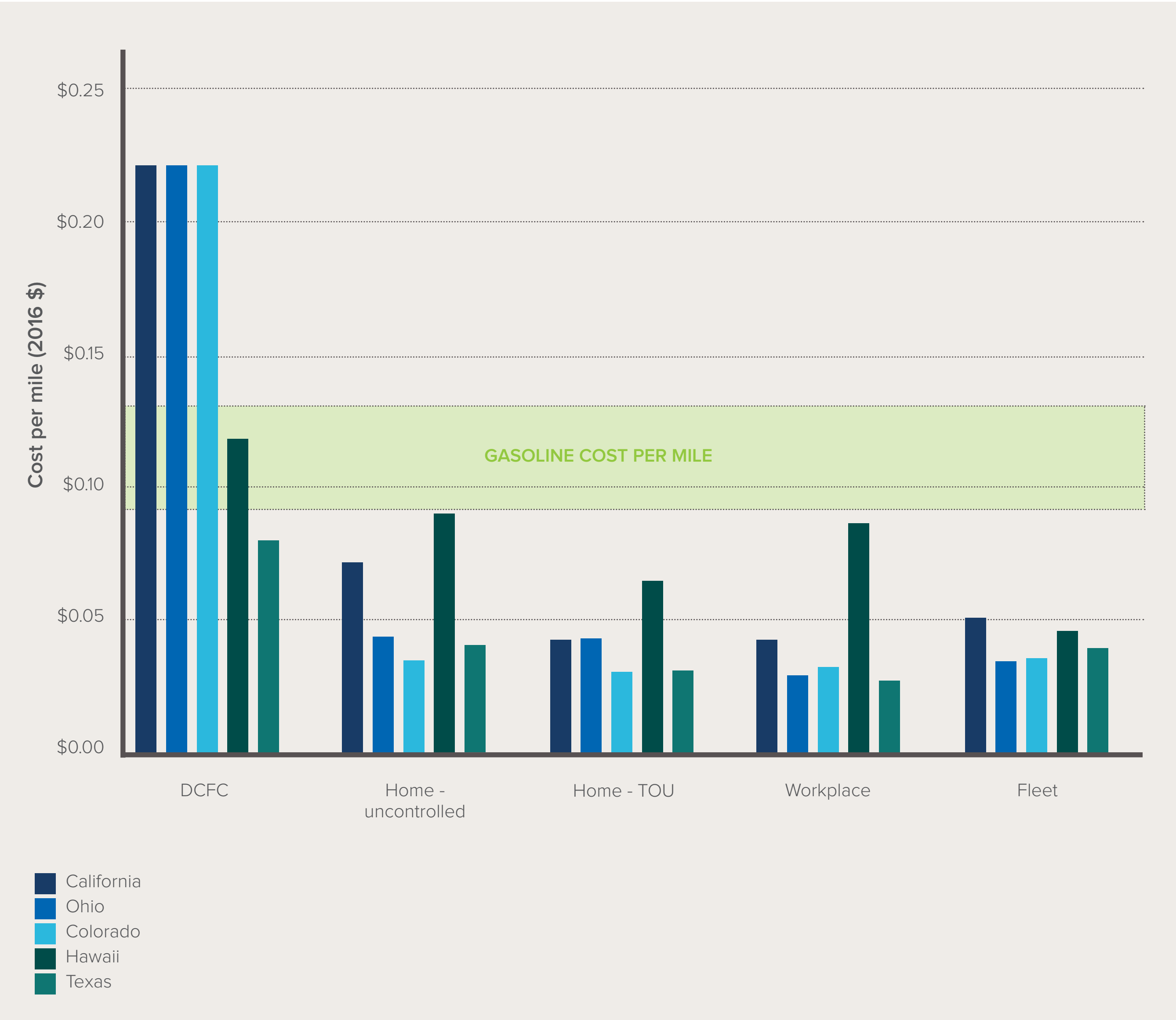
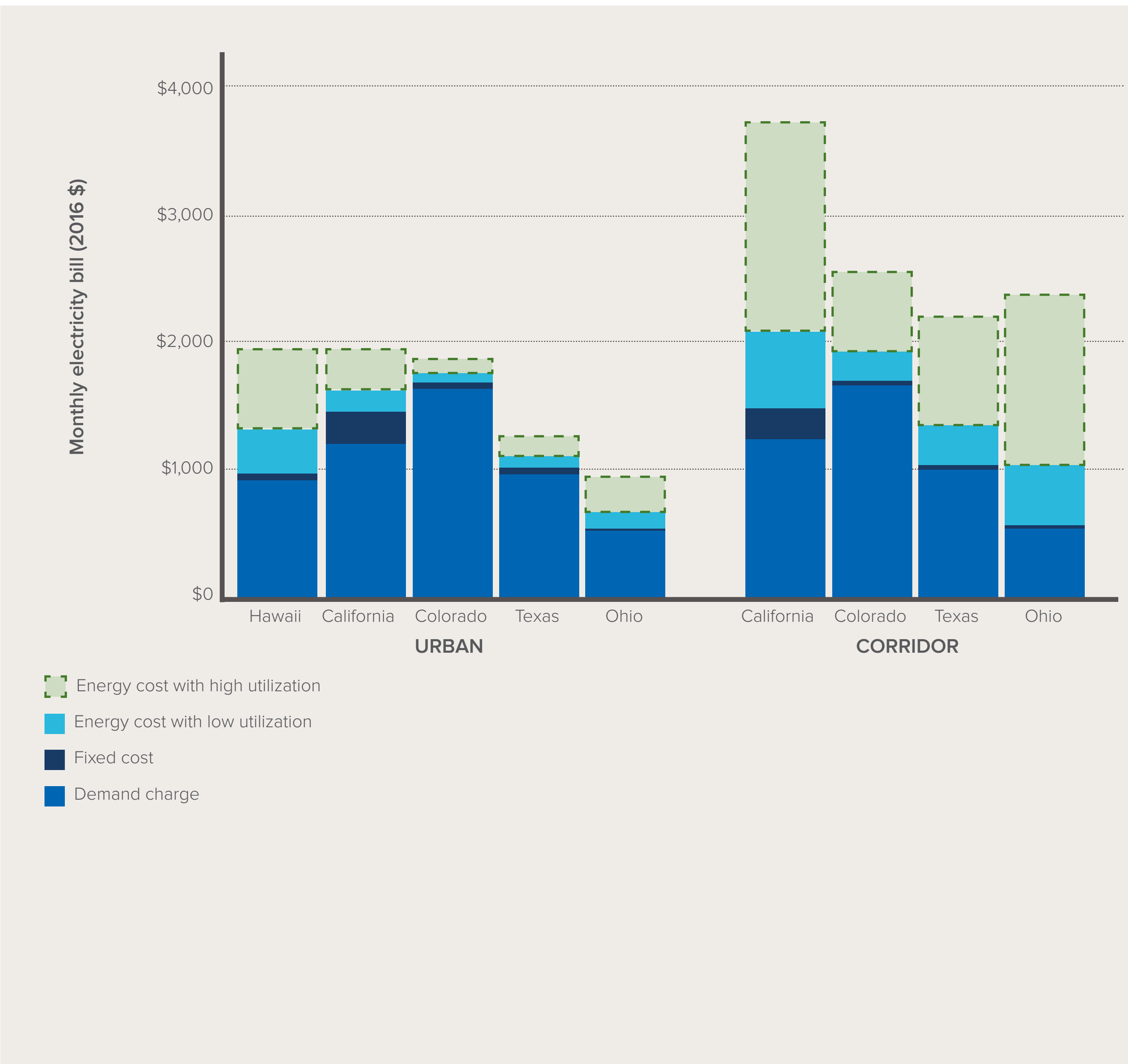


Exhibit JRB-5

Finally, as shown in Figure 12, we break down the monthly utility bill of a representative public DCFC station with two 50 kW ports for each state, and identify the portions of the cost that come from demand charges, energy charges, and fixed charges.

FIGURE 12

MONTHLY HOST-SITE UTILITY BILL FOR DCFC OPERATION (TWO 50 KW PORTS)

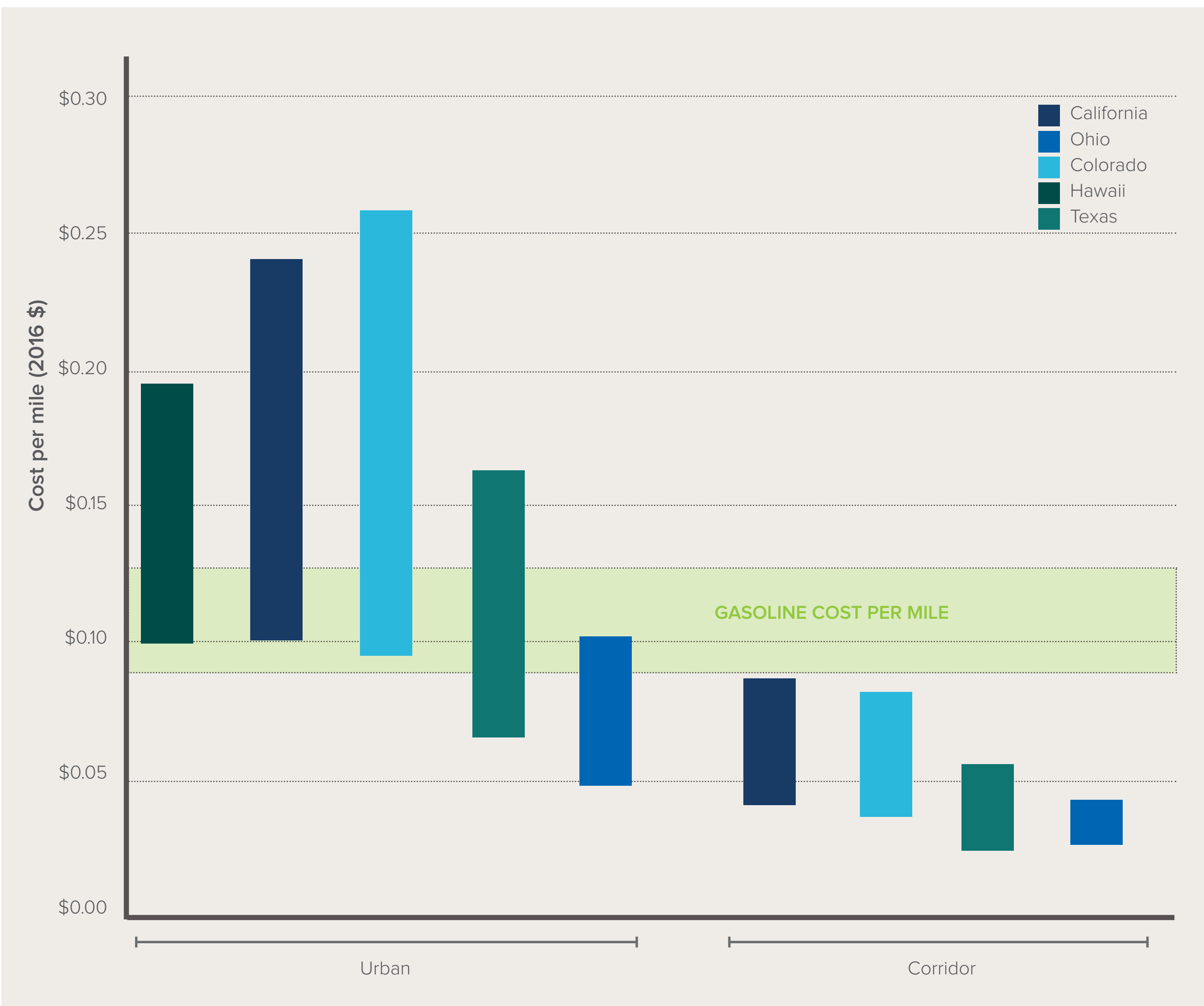


We show in Figure 13 how those host-site utility costs translate to a cost per mile of charge delivered under two utilization scenarios (high and low) for two different DCFC locations: an urban location, and a rest-stop location along a long-distance corridor. In this analysis, urban utilization ranges from 3% to 9% and corridor utilization from 10% to 39%. It is important to note that findings for urban charge sessions were based on actual EVSE utilization in 2016 that was primarily composed of shorter-range EV charge events, while the corridor utilization was simulated and based on higher-range EVs fueling as often as an ICE vehicle would.[81]

See the Appendix for details on the methodology of this analysis.

FIGURE 13

ELECTRICITY COST RANGE FOR HOST SITE TO DELIVER ONE MILE OF CHARGE VIA DCFC



CALIFORNIA

California is by far the leading state for vehicle electrification, with nearly half the national fleet of EVs, the largest fleet of charging stations, the largest share of EVs on the road, at over 2% (299,038 as of May, 2017),[82] and the most aggressive official target for EV adoption (1.5 million EVs by 2025).[83]

OWNERSHIP

California has an organized, quasideregulated electricity market with competitive generation and a burgeoning number of customers who are enrolled in Community Choice Aggregations (CCAs), which have control over procuring electricity for their customers. Since California straddles the line between being a fully regulated and fully deregulated market, it is perhaps unsurprising that regulators are reviewing plans that will test several ownership models for EV charging infrastructure. The three major investor-owned utilities (IOUs) in California—Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), and Pacific Gas and Electric (PG&E)—propose to spend over $1 billion on charging infrastructure. We summarize these large, multi-faceted investment programs as follows:[84]

- Most of the money in SCE's plan would be spent on make-ready locations that would support a variety of third-party charging stations, of which most would be for medium- and heavy-duty vehicles like delivery trucks and forklifts.
- SDG&E would spend most of its investment on Level 2 residential chargers that it would own and operate. These chargers would be under SDG&E's TOU rate and would be programmable to take advantage of that rate.
- PG&E's charging station deployments would be a hybrid of programs, and mostly aimed at DCFCs. It would include investments in make-ready locations for third-party chargers, as well as chargers that it would own and operate.

In time, California's "all of the above" strategy for charging station ownership could show which approaches to deployment are most effective. For example, it may show that utilities are able to deploy charging stations faster than private companies are. It may also give regulators some insight on what kinds of investments are appropriate to be socialized through the rate base. For example, it may show that deploying charging stations into low-income areas is best accomplished as a rate-based investment, whereas wealthier areas are more easily served by private sector companies who can earn sufficient revenue in those areas to make the investment worthwhile.

SITING STRATEGIES

In our view, hubs of high-speed DCFC charging stations located to serve high-usage fleet vehicles are probably sensible, no-regrets solutions for California's major cities. High-speed hubs are practical for high-usage corridors and commuting routes as well. Widespread home and workplace charging on Level 2 chargers would also make sense for California, since the state has a goal to achieve a high degree of vehicle electrification.

GRID INTEGRATION

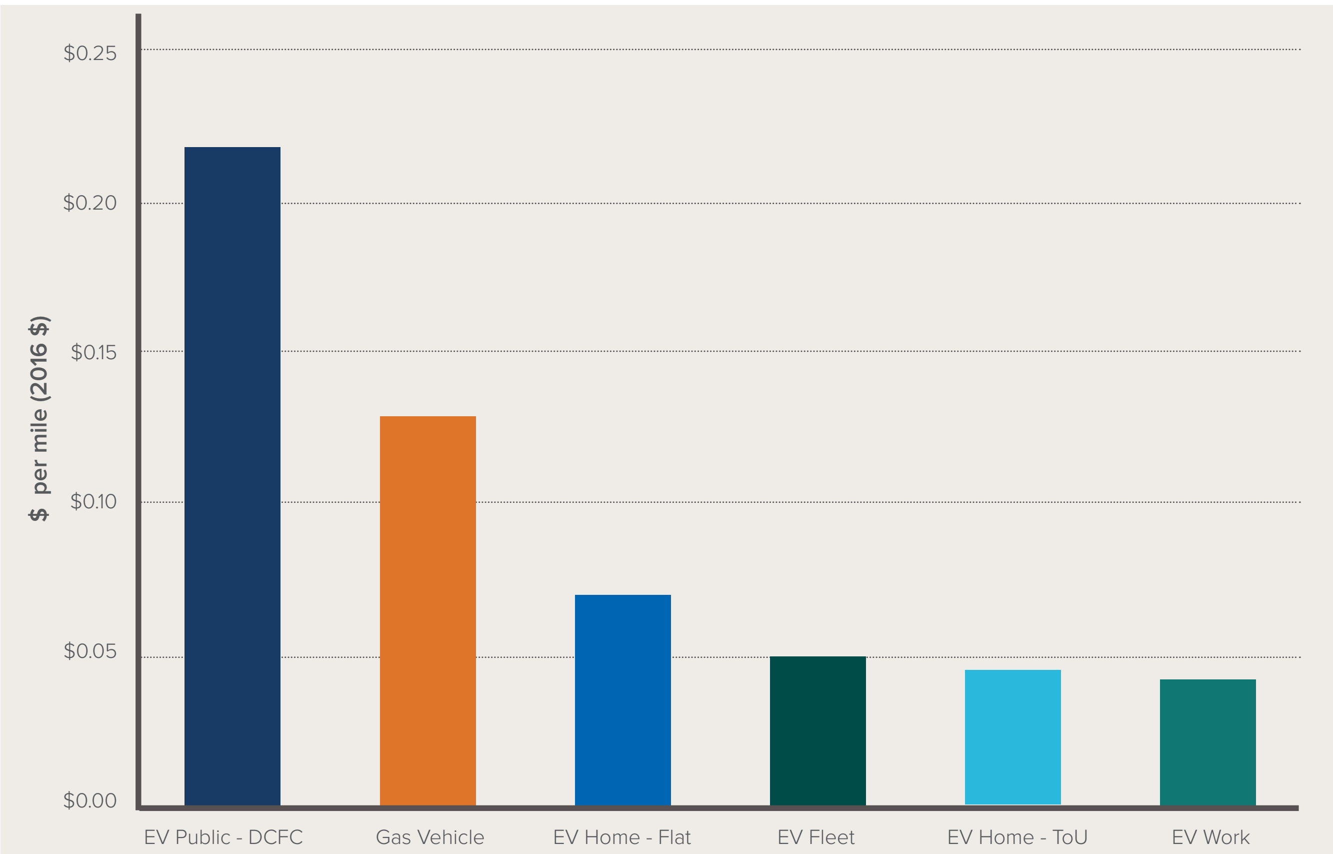
California's "duck curve," in which demand for dispatchable electricity sharply increases as the sun goes down and solar generation tapers off, has gotten steeper sooner than the state's forecasters expected.[85] A surfeit of solar power on the California grid is contributing to an oversupply condition in the midday, which is forcing the grid operator to curtail wind and solar output and driving wholesale power into negative pricing. Managing the charging of a larger number of EVs in California, preferably using passive management techniques like TOU tariffs, could help alleviate these conditions and flatten out the curve for dispatchable supply. By using EVs to absorb excess solar and wind, California could increase its share of the total electricity supply, and displace some of the state's natural gas consumption. Colocating solar and battery storage with charging depots could increase the share of solar power on California's grids even further, by absorbing it even when the charging stations are not in use.

COST OF CHARGING

The cost of charging an EV in Southern California can be as low as $0.04/mile if charged during workday hours at a workplace and as high as $0.22/mile if using a public DCFC network.

FIGURE 14

EV CHARGING COSTS IN CALIFORNIA, SCE

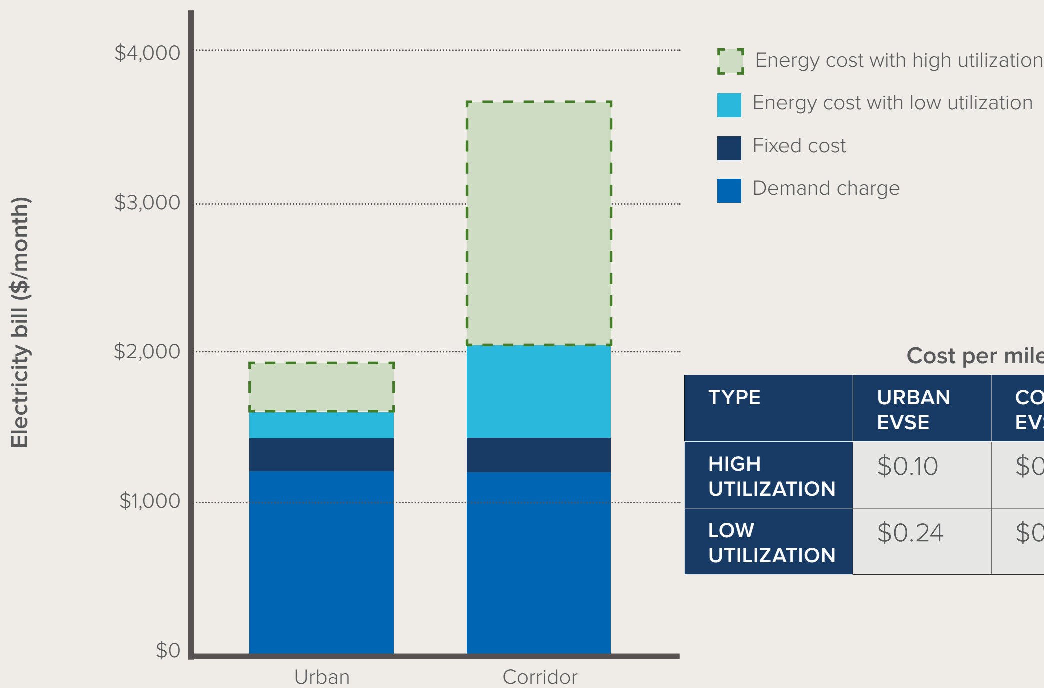


Looking across the various charging options and the price signals they send to the EV owner, we developed a set of hypotheses around these results:

- Workplace charging is significantly cheaper than uncontrolled home charging, and slightly cheaper than home smart charging. This sends drivers a signal that it's better to charge at work, or at home on a TOU rate.
- All non-fast charging options are significantly cheaper than fueling an ICE vehicle. This suggests that consumers will seek the lower cost of Level 1 or Level 2 charging, which could enable managed charging to provide grid services.
- Charging on a DCFC is costlier per mile than fueling an ICE vehicle. As such, nonfleet drivers are likely to view it as a premium option that they'll use infrequently, which does not make it cheaper to own an EV than an ICE.

FIGURE 15

UTILITY BILL FOR A REPRESENTATIVE DCFC IN CALIFORNIA ON THE SCE GRID



Cost per mile

TYPE	URBAN EVSE	CORRIDOR EVSE	GAS
HIGH UTILIZATION	$0.10	$0.04	$0.13
LOW UTILIZATION	$0.24	$0.09	

In Figure 15 we present the monthly utility bill as a stacked bar chart, by bill component, including the energy cost range associated with a high and low charger utilization rate. The inset table shows the subsequent cost to deliver a mile of charge under each scenario for high and low utilization rates. The maximum monthly demand is based on the maximum power output of the DCFC, which does not vary with utilization, so the demand component of the bill is the same for urban and corridor stations regardless of the charger utilization. This utility bill analysis provides a few key insights into DCFC operation in Southern California:

- In all but the low-utilization urban locations, the cost to deliver one mile of charge is lower than the gasoline equivalent.
- The demand charge is the largest component of the bill in urban locations under both high and low utilization scenarios, and ranges from 30%–60% for the corridor locations.
- Properly sited and highly utilized corridor DCFC can deliver reasonable costs per mile under existing tariff structures, but it will be challenging for urban DCFC to compete with gas-equivalent costs under existing tariffs.

The cost to deliver one mile of charge via DCFC stations represents only a subset of the total cost burden to a DCFC network operator or host site, and thus should not be confused with the price that that host/owner will be able to offer to a prospective EV charging customer. For example, a DCFC operator may also need to pay for charger maintenance, network fees, routine overhead, and parking space leases.

COLORADO

With EVs comprising 0.56% (10,033 as of May, 2017)[86] of vehicles on the road, Colorado was 15th in the nation in terms of the absolute number of EVs, and 10th in EVs per capita in 2015.[87] Colorado offers a variety of other incentives for purchasing an EV, including the largest state income tax credit (up to $5,000), in addition to the $7,500 federal tax credit.[88] Xcel Energy, the largest utility in the state, supports additional incentives, such as special offers for the Nissan Leaf, home charging for as little as $1 per gasoline-gallon equivalent, and multiple electricity rate plans.[89]

OWNERSHIP

Colorado has a fully regulated electricity market, so one might think the path of least resistance for deploying chargers in the state would be as a rate-based utility investment. However, although Colorado state law allows IOUs to own and operate charging stations, they are prohibited from using regulated funding to purchase or support these stations.[90] And a corporation or individual that resells electricity supplied by a public utility to charge EVs is specifically exempted from regulation as a public utility.[91] This legal framework is more likely to favor private ownership and deployment of charging stations, and accordingly, the state offers significant rebates for charging station deployments.[92] However, there is no prohibition against utilities building make-ready infrastructure.

SITING STRATEGIES

Charging hubs designed to support ride-hailing services can work in the major population centers of Denver, Boulder, and Colorado Springs. But many drivers will want to be able to drive to the mountains, where chargers are scarce and temperatures can be cold. This suggests that, at minimum, destination communities (like the ski resort towns) will want to install a sufficient number of DCFC and Level 2 chargers to give drivers confidence that they can make a trip there and back home without the need to recharge interfering with their recreational plans, perhaps with dedicated staff at the resorts to manage and optimize the use of the charging stations. For residents in the nonmetro areas of Colorado, home and workplace charging on Level 2 chargers may be the most practical option.

GRID INTEGRATION

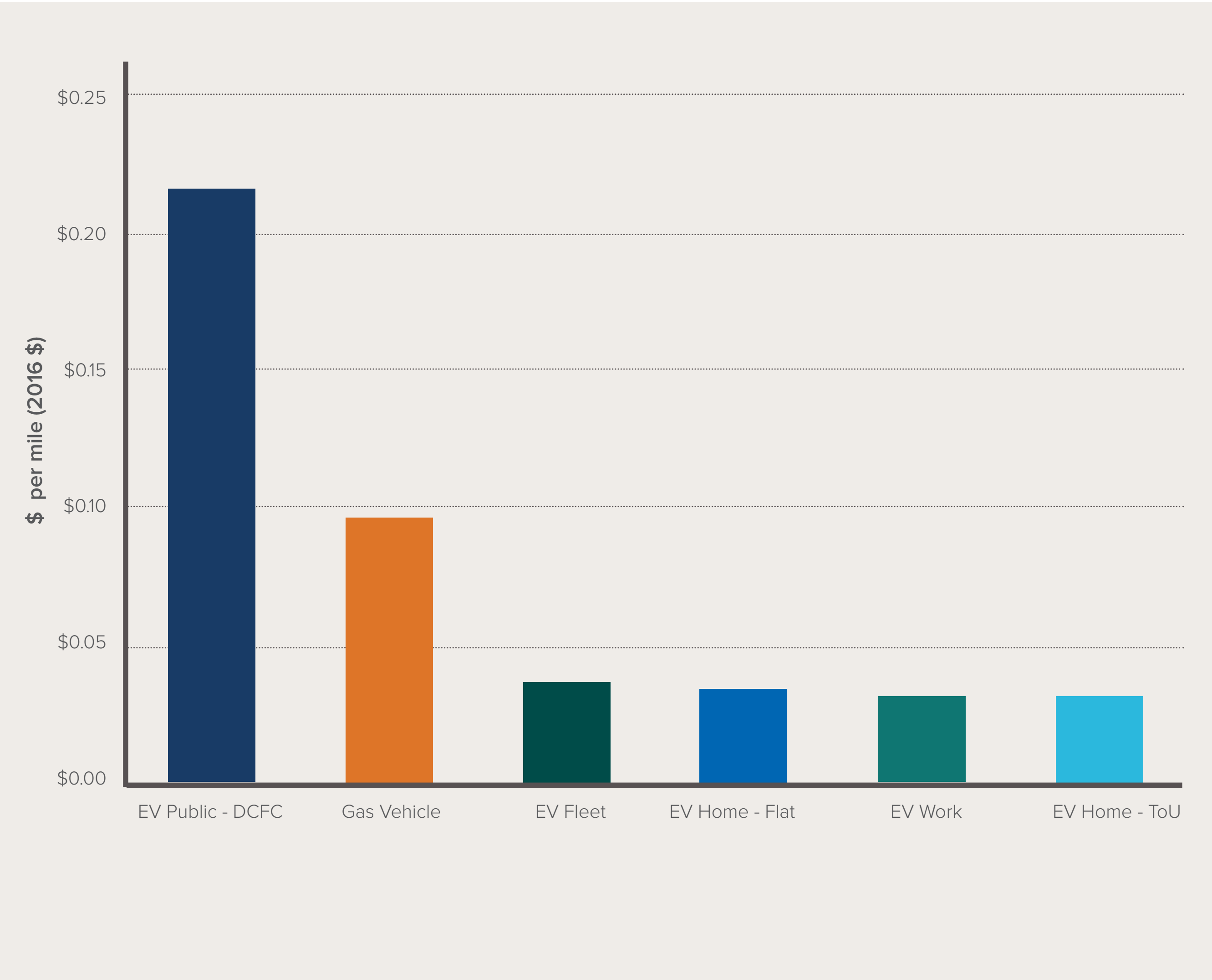
Although Colorado has abundant wind and solar resources, as well as a significant base of residents who support renewable energy, its grid is primarily coal-fired. Demand on the Xcel Energy grid is also typically low during the midday solar peak of the non-summer months.[93] This suggests that if Xcel Energy were to offer a TOU or other special rate for Level 2 EV charging, preferably on a dedicated meter, which featured off-peak pricing during the midday, it could take advantage of the midday solar power availability and potentially begin to displace its coal generation. Similarly, a TOU rate coupled with Xcel's non-EV specific commercial rate ("Secondary General Low-Load Factor") could offer DCFC operators a low-cost electricity supply coincident with transportation demand.[94] Occasionally, Xcel Energy has also had to curtail wind production, primarily for balancing (e.g., oversupply) and transmission (e.g., line constraints and outages) reasons.[95] This suggests an opportunity to use managed Level 2 charging to alleviate such temporary grid conditions and avoid curtailment. On the whole, there is significant opportunity for Colorado to displace coal and increase the share of wind and solar on its grid through the use of time-varying rates and active charge management.

COST OF CHARGING

The cost of charging an EV in Colorado can be as low as $0.03/mile if charged at home during the off-peak hours of a TOU rate, and as high as $0.22/mile if using a public DCFC.

FIGURE 16

EV CHARGING COSTS IN COLORADO ON THE XCEL GRID

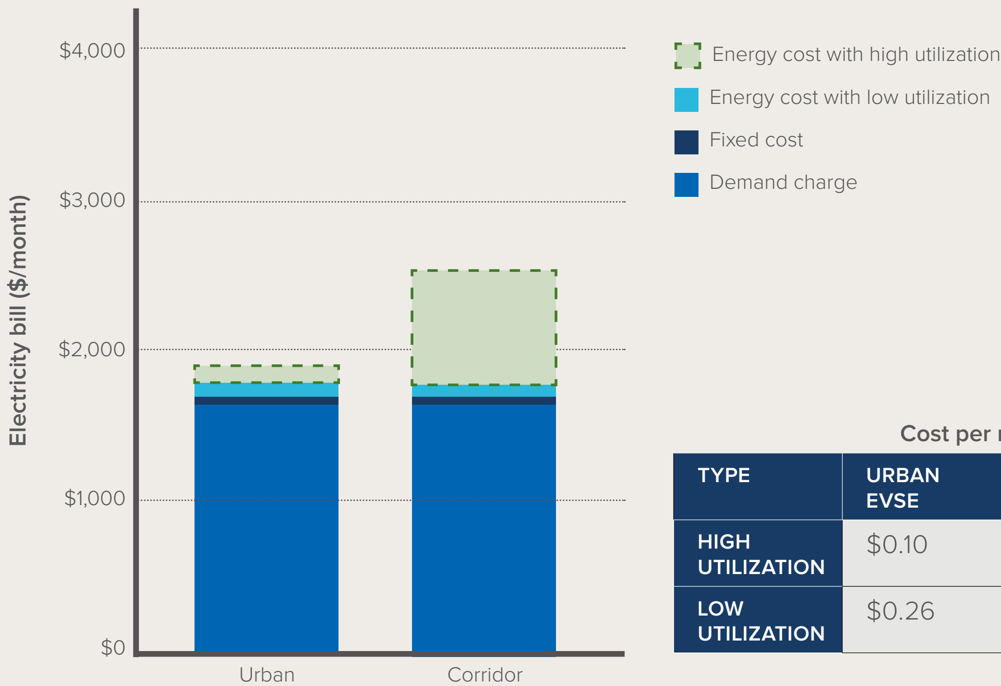


Looking across the various charging options and the price signals they send to the EV owner, we developed a set of hypotheses around these results:

- There isn't much difference between the costs of charging at work, charging at home in an uncontrolled manner, and charging at home in a controlled manner. This will motivate EV drivers to charge when it's convenient for them, not when it's best for the grid.
- All non-fast charging options are significantly cheaper than fueling an ICE vehicle. This suggests that consumers will seek the lower cost of Level 1 or Level 2 charging, which could enable managed charging to provide grid services.
- Charging on a DCFC is costlier per mile than fueling an ICE vehicle in urban locations. As such, non-fleet drivers are likely to view it as a premium option that they'll use infrequently, which does not make it cheaper to own an EV than an ICE.

FIGURE 17

UTILITY BILL FOR A REPRESENTATIVE DCFC IN COLORADO ON THE XCEL GRID



Cost per mile

TYPE	URBAN EVSE	CORRIDOR EVSE	GAS
HIGH UTILIZATION	$0.10	$0.04	$0.10
LOW UTILIZATION	$0.26	$0.08	

This utility bill analysis provides a few key insights into DCFC operation in Colorado:

- In urban locations with low utilization, charging on a DCFC is costlier than fueling an ICE vehicle. In urban locations with high utilization, charging on a DCFC is at parity with fueling an ICE vehicle. In corridor locations, DCFC charging costs less than fueling an ICE vehicle under both low- and high-utilization rates.
- Demand charges make up much of the bill for urban and corridor stations under both high- and low-utilization scenarios, while energy charges vary slightly across scenarios. This results in a high fixed cost of operation that is largely independent of utilization, and will make for challenging economics for DCFC ownership in all but the busiest locations.

OHIO

With EVs comprising 0.15% (6,973 as of May, 2017)[96] of vehicles on the road, Ohio was 16th in the nation in terms of absolute number of EVs, and 32nd in EVs per capita in 2015.[97]

OWNERSHIP

Ohio has a few incentives for EV purchases and related programs, and offers low-interest loans for businesses, nonprofits, public schools, and local governments that want to install charging stations.[98] Of greatest relevance today are three major new programs in the state:

- The Ohio Department of Transportation plans to spend $4 billion over the next two years equipping the state's highways with autonomous-vehicle enabling technology, including "smart mobility corridors" along Interstate 270 around Columbus and on I-90 from Cleveland to the Pennsylvania border.[99]
- The Smart Columbus program, with seed funding of $50 million from the U.S. Department of Transportation and Vulcan, will take an integrated approach to 15 separate elements of smart mobility, including electric autonomous vehicles.[100]
- AEP, a major utility in Ohio, has filed a rate case with the Public Utilities Commission of Ohio (PUCO) seeking to rate-base 1,275 stations over a four-year demonstration period, including 275 public charging stations (of which 25 would be DCFC) and 1,000 residential chargers. The utility would own and operate the charging stations and offer free charging on them. However, the Electric Vehicle Charging Association, a group of commercial charging infrastructure companies, is a party to the case and is negotiating with AEP to ensure the plan fosters competition.[101]

Ohio has a competitive market for electricity generation, although all residents receive their gas and electricity from a single retail energy provider of their choice, which is regulated by PUCO.

SITING STRATEGIES

Electric charging hubs for fleet and commuter vehicles appear to be part of the Smart Columbus plan, which could form the basis for public charging infrastructure across Ohio, radiating out from Columbus. However, the very nascent state of charging infrastructure and electric mobility planning in Ohio leaves plenty of room for the state to change directions. The outcome of AEP's proposal to install, own, and operate charging stations will almost certainly become an important precedent in the state, and indicate which direction the state is likely to go on the question of charging station ownership.

GRID INTEGRATION

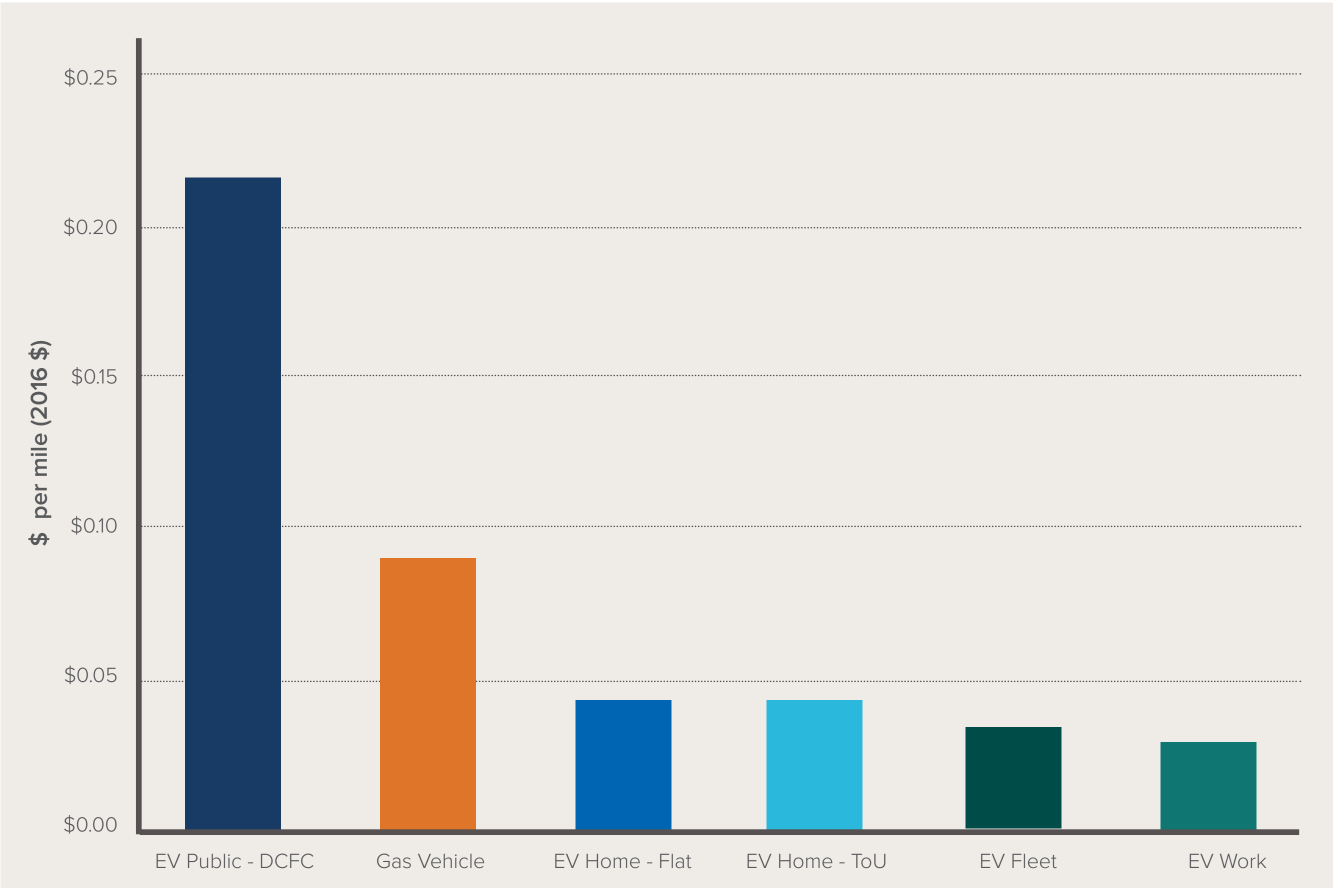
With a grid that is mostly powered by coal, has a modest amount of existing wind and solar production, and a relatively small number of EVs on the road, but will potentially have a major expansion of charging infrastructure through AEP and smart mobility infrastructure in Columbus and on Ohio's highways, the state has an excellent opportunity to use its EV infrastructure build-out as a path to accommodating more renewable electricity, displacing coal, and setting good precedents for EV-friendly rate design and managed charging from the ground up.

COST OF CHARGING

The cost of charging an EV in Ohio can be as low as $0.03/mile if charged at work, and as high as $0.22/mile if using a public DCFC.

FIGURE 18:

EV CHARGING COSTS IN OHIO ON THE AEP GRID

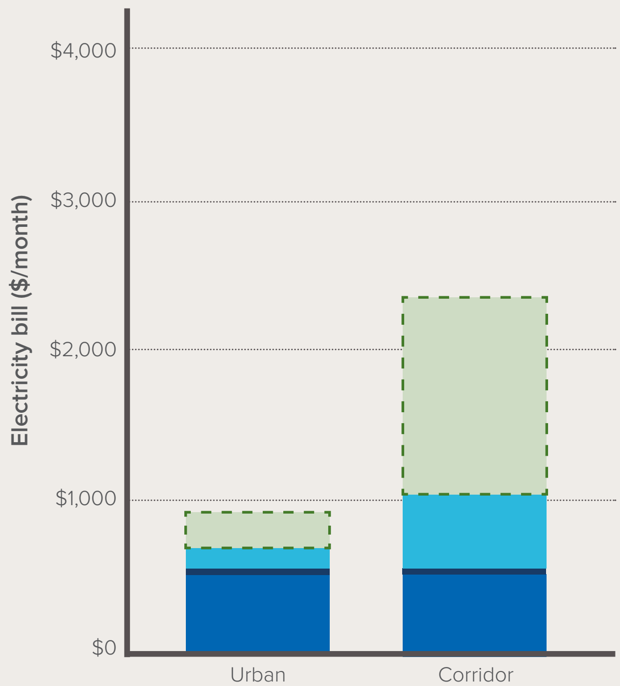


Looking across the various charging options and the price signals they send to the EV owner, we developed a set of hypotheses around these results:

- There is only an 8% difference in cost between uncontrolled and controlled charging while at home. This price differential is insufficient to motivate drivers to charge when grid costs are lowest, and suggests the need for a more differentiated TOU rate.
- Workplace charging is 30% cheaper than home charging. This could be enough to motivate drivers to charge at work more often if workplace chargers were available.
- All non-fast charging options are significantly cheaper than fueling an ICE vehicle. This suggests that consumers will seek the lower cost of Level 1 or Level 2 charging, which could enable managed charging to provide grid services.
- Charging on a DCFC is costlier per mile than fueling an ICE vehicle. As such, nonfleet drivers are likely to view it as a premium option that they'll use infrequently, which does not make it cheaper to own an EV than an ICE.

FIGURE 19

UTILITY BILL FOR A REPRESENTATIVE DCFC IN OHIO ON THE AEP GRID



Cost per mile

TYPE	URBAN EVSE	CORRIDOR EVSE	GAS
HIGH UTILIZATION	$0.05	$0.03	$0.09
LOW UTILIZATION	$0.10	$0.05	

This utility bill analysis provides a few key insights into DCFC operation in Ohio:

- The cost to deliver one mile of charge is lower than the gasoline equivalent in all cases except for the low-utilization scenario in an urban location, where the cost is close to the gasoline equivalent.
- Demand charges are a lesser component of the bill than in other states. This may lead to a more robust network of DCFC where low-utilization stations can operate profitably.
- All non-fast charging options are significantly cheaper than fueling an ICE vehicle. This suggests that consumers will seek the lower cost of Level 1 or Level 2 charging, which could enable managed charging to provide grid services.

TEXAS

With EVs comprising 0.23% (18,930 as of May, 2017)[102] of vehicles on the road, Texas was 6th in the nation in terms of absolute number of EVs, and 28th in EVs per capita in 2015.[103]

OWNERSHIP

The state has numerous incentives for EV purchases and related programs. For example, rebates are available for lower-income households that purchase an EV to replace an older, high-emissions vehicle; certain fleets of state agency vehicles must procure alternative fuel vehicles (including EVs); grants are available to build electrification infrastructure in certain areas; and grants are available to replace diesel fleets with hybrid electric vehicles.[104] Austin Energy, the 8th-largest public utility in the U.S., also has a variety of programs to support EVs in Austin, including rebates (up to $1,500) toward the cost of purchasing and installing a Level 2 charger; a special residential TOU rate for Level 2 chargers; and a plan that offers unlimited charging for $4.17 per month at any of its more than 250 Plug-In EVerywhere stations.[105]

Texas has the most deregulated market in the country, with approximately 85% of the state having a choice of electricity retailer. This might suggest that Texas is inclined toward competitive markets for charging infrastructure, but state law sets a different standard. The Texas Public Utility Regulatory Act requires sellers of electricity to demonstrate that they have "the financial and technical resources to provide continuous and reliable service to customers in the area for which the certification is sought," which has had the effect of barring competitive private charging companies from owning or operating EV charging stations. However, some charging companies have worked around this restriction by partnering with municipal utilities, like Austin Energy, to provide EV charging services.[106] Accordingly, the path of least resistance for private charging companies to increase their deployments in Texas may be through partnerships with municipal utilities, which have a fair amount of latitude to develop EV programs, offer low-cost service that will entice EV drivers, and provide patient capital with low financing costs for a long-term, capital-intensive build-out of charging infrastructure. In areas of Texas served by IOUs, the only two options seem to be either to allow the utilities to build and rate-base charging stations, or to change the law to exempt EV charging stations or their owners and operators from regulations applicable to public utilities, as some 16 states have already done.[107] Whether this state of affairs is by design, or is merely an unintended consequence of old laws, is unclear.

SITING STRATEGIES

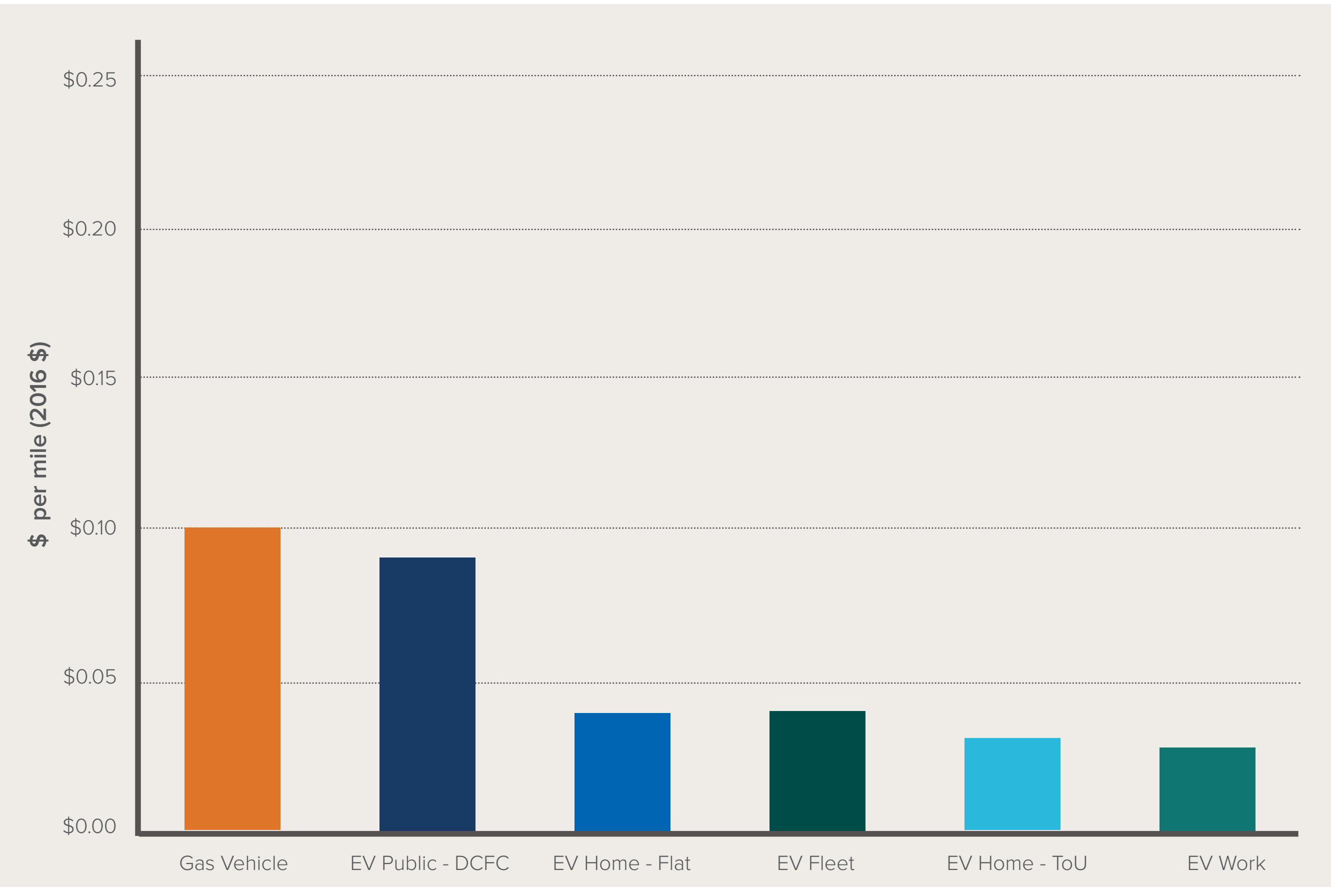
The most useful siting of charging stations in Texas will probably follow similar strategies as in California: high-speed DCFC charging hubs located to serve high-usage fleet and ride-hailing vehicles; and DCFC along high-usage corridors and commuting routes around major cities. And given the relative preponderance of single-family homes with garages, widespread home and workplace charging on Level 2 chargers would offer the best opportunity for using chargers as grid assets. Given the long distances between rest stops on some major highways, it may also be advisable for Texas to deploy DCFC at rest areas and services stops along those routes.

GRID INTEGRATION

Although transmission expansion and market redesign have reduced the incidence of outright wind-power curtailment in Texas in recent years, ERCOT still experiences system-wide negative pricing in the middle of the night due to an oversupply of wind.[108] These negative prices have made it very difficult for merchant generators to survive in ERCOT, and have led to untoward outcomes, such as the bankruptcy of new, highly efficient, low-emissions gas plants like Panda Temple.[109] Instead of reducing the output of zero-carbon generators and forcing low-carbon, efficient generators into bankruptcy, effective use of TOU rates and managed nighttime Level 2 charging by EVs could absorb extra wind power, allow ERCOT to increase the share of wind power on its system, maintain wholesale

FIGURE 20

EV CHARGING COSTS IN TEXAS ON THE AUSTIN ENERGY GRID



pricing that can support new investment, and displace coal power units instead.

COST OF CHARGING

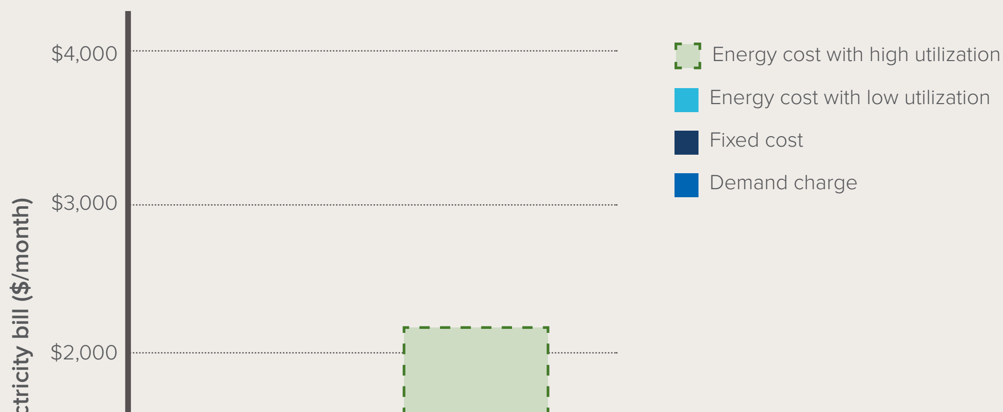
The cost of charging an EV in Austin, Texas, can be as low as $0.03/mile if charged at work, and as high as $0.08/mile if using a public DCFC.

Looking across the various charging options and the price signals they send to the EV owner, we developed a set of hypotheses around these results:

- All EV charging options are lower than the equivalent cost of fueling a gas vehicle. This is largely because of Austin Energy's Plug-in-EVerywhere network, which offers a very inexpensive public charging program for EV owners that includes both Level 2 and DCFC chargers.
- There is a 20% difference in cost between uncontrolled and controlled charging while at home. The price differential of this tariff may be insufficient to substantively shift charging to off-peak periods, and points up an opportunity to use a TOU tariff with a higher differential to help flatten the load profile on the Austin Energy system.
- Workplace charging is 30% cheaper than home charging. This might motivate drivers to charge at work more often if workplace chargers were available.

FIGURE 21

UTILITY BILL FOR A REPRESENTATIVE DCFC IN TEXAS ON THE AUSTIN ENERGY GRID



Cost per mile

TYPE	URBAN EVSE	CORRIDOR EVSE	GAS
HIGH UTILIZATION	$0.07	$0.02	$0.09
LOW UTILIZATION	$0.16	$0.06	

This utility bill analysis provides a few key insights into DCFC operation in Austin, Texas:

- The cost to deliver one mile of charge is lower than the gasoline equivalent in all cases except for the low-utilization scenario in an urban location.
- The demand charge is the largest component of the bill in urban locations under the high-utilization scenario, and ranges from 40%–75% for the corridor locations. This would make it difficult to operate the chargers profitably at very low-utilization charging sites.
- High-utilization corridor charging is very cost-competitive at $0.02/mile.

HAWAII

With EVs comprising 1.2% (6,178 as of May, 2017)[110] of vehicles on its roads, Hawaii was 19th in the nation in terms of absolute number of EVs, but second in EVs per capita (after California) in 2015.[111]

OWNERSHIP

Hawaii has numerous incentives for EV drivers and charging infrastructure. For example, special rebates are available for the Nissan LEAF under a partnership with Nissan;[112] the Hawaiian Electric Company offers TOU rates for residential and commercial EV charging on Oahu, in Maui County, and on the Island of Hawaii; EV drivers have access to high-occupancy vehicle lanes and are exempt from some parking fees; multi-family residential dwellings and townhouses have the explicit right to site charging stations on their premises; public parking facilities that have at least 100 parking spaces must designate at least one parking space specifically for PEVs; and PEVs top the list of eligible vehicles that state and county agencies must purchase. Other programs are under consideration, including a request by the Hawaii Senate to adopt rules that encourage the use of EVs for taxis at Honolulu International Airport. The state also intends to embrace EVs as part of its strategy to meet 100% of its energy needs from energy-efficient and renewable sources by 2045—a goal that implicitly rules out reliance on petroleum fuels.[113]

Hawaii has a fully regulated electricity market, in which Hawaiian Electric is the primary regulated monopoly. But the island state has also embraced private ownership of charging infrastructure and has a well-developed ecosystem of charging networks providing service in the state.[114] Charging station owners are exempted from rules that apply to public utilities. State agencies and advocates are largely aligned on the need for vehicle electrification, although the funding model for deploying additional chargers remains a subject of debate.

SITING STRATEGIES

The size of the Hawaiian Islands makes it possible to make nearly all normal trips within the 30- to 60-mile range of most EVs. Even the longest numbered highway in Hawaii, state route 11 on the Big Island, is within the range of a single Chevy Bolt charge, at 122 miles. Accordingly, Level 2 charging is adequate for most purposes in Hawaii, and Level 2 chargers constitute the bulk of the state's 250+ charging stations. The need for DCFC is primarily limited to high-traffic shopping areas and tourist destinations. As a result, Hawaii will be able to provide ubiquitous charging infrastructure at a relatively low cost, while also having an excellent opportunity to manage charging stations to provide grid services.

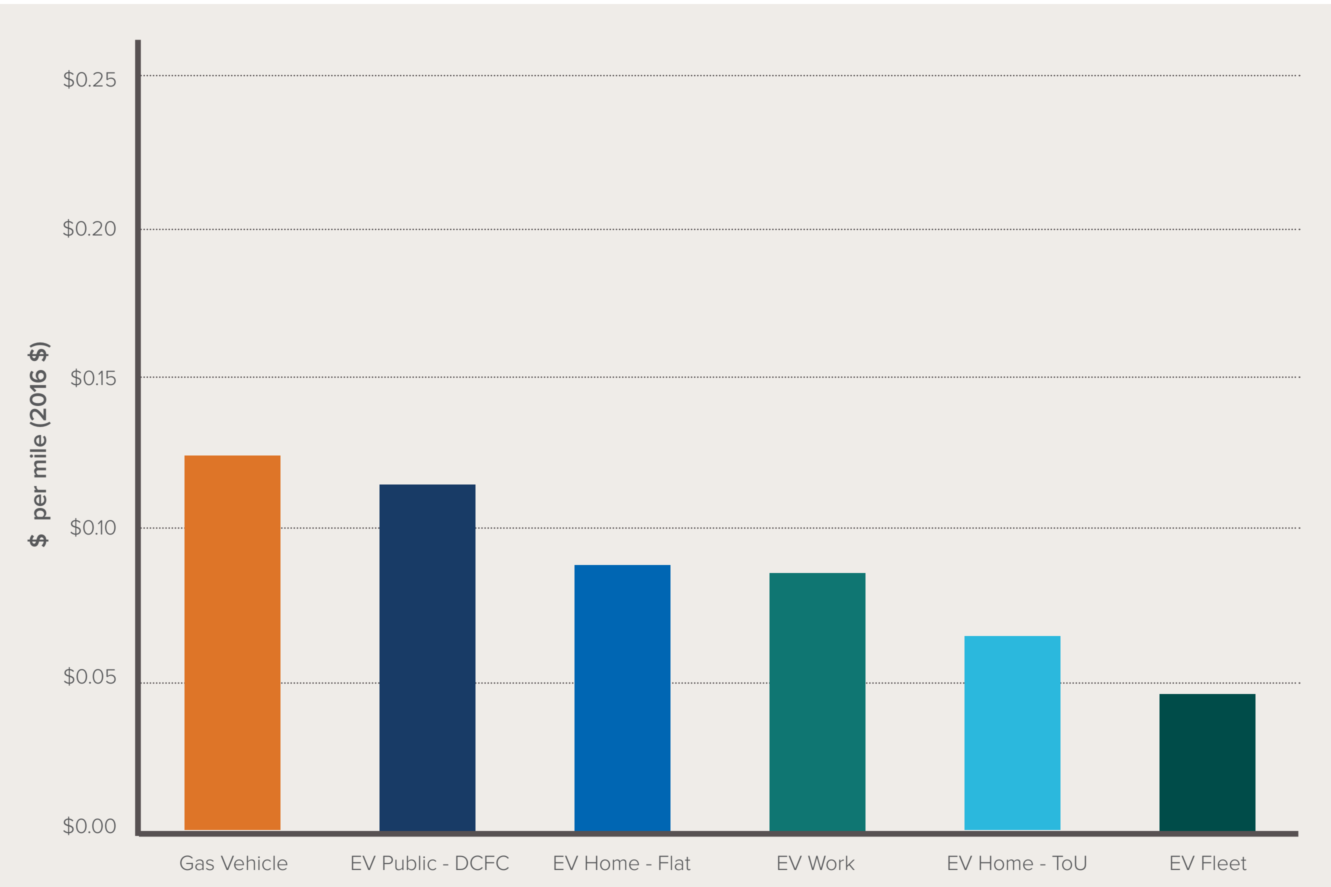
GRID INTEGRATION

With a grid that is 73% powered by petroleum, Hawaii has the highest residential electricity prices in the nation (29.6 cents/kWh in 2015)[115] and the most urgent need of any state to switch its grid power from expensive petroleum to cheap and abundant local renewable electricity. Unlike all the other states, vehicle electrification in Hawaii can displace petroleum twice: once in the vehicles, and once in the grid power supply. Hawaii has the third-highest solar capacity per capita,[116] but it also experiences substantial curtailment of its solar and wind output due to oversupply in low load periods, and balancing challenges such as maintaining frequency and stability which arise from having small balancing areas on each island with limited interconnection.

A comprehensive build-out of Level 2 charging stations on Hawaii with smart TOU rate design and managed charging could radically improve Hawaii's energy and fiscal balance by absorbing more solar and wind instead of curtailing it, and by displacing petroleum. It would also gradually lead to a lower unit cost for wind and solar, because in Hawaii the cost of curtailment is built into the price of fixed-price contracts, rather than via direct compensation.[117] Deploying more charging infrastructure would lead naturally to a virtuous cycle in which more chargers beget more EVs, which displace

FIGURE 22

EV CHARGING COSTS IN HAWAII ON THE HAWAIIAN ELECTRIC GRID



more petroleum, which reduces the cost of driving and grid power simultaneously, which makes vehicle electrification even more financially attractive, and which enables the absorption of more wind and solar with zero marginal cost.

COST OF CHARGING

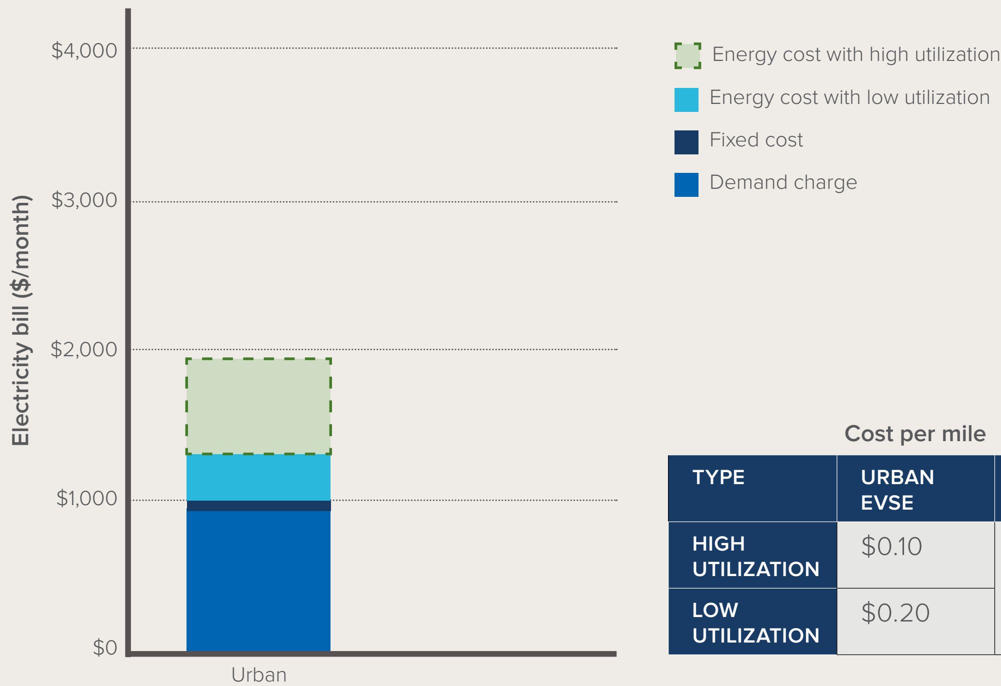
The cost of charging an EV in Hawaii can be as low as $0.05/mile for fleets; $0.06/mile if personally owned and charged at home; and as high as $0.011/mile if using a public DCFC.

Looking across the various charging options and the price signals they send to the EV owner, we developed a set of hypotheses around these results:

- All EV charging options are lower than the equivalent cost of fueling an ICE vehicle. This is largely because of Hawaiian Electric's EV-U pilot tariff, which offers fixed-fee DCFC access, and Hawaii's high cost of gasoline.
- There is a 27% difference in cost between uncontrolled and controlled home charging, which offers a moderately persuasive price signal to drivers to charge during off-peak periods.
- Workplace charging is more expensive than controlled home charging, and only slightly less expensive than uncontrolled home charging. This price differential would not be particularly effective at motivating

FIGURE 23

UTILITY BILL FOR A REPRESENTATIVE DCFC IN HAWAII ON THE HAWAIIAN ELECTRIC GRID[ii]



Cost per mile

TYPE	URBAN EVSE	GAS
HIGH UTILIZATION	$0.10	$0.12
LOW UTILIZATION	$0.20	

workplace charging, but daytime workplace charging is what the Hawaiian grid needs to avoid midday solar curtailment.

This utility bill analysis provides a few key insights into DCFC operation in Hawaii:

- Urban charging is costlier than gasoline fueling for nearly all utilization levels evaluated.
- High energy costs make the economics of EV charging more challenging in low-utilization scenarios.

[ii] Corridor charging is not applicable to the Hawaii case study due to the unique driving patterns and distances traveled on the Hawaiian Islands, and was therefore not included in this analysis.

04 LET'S GET MOVING

eTourEurope, courtesy of Werner Hillebrand-Hansen

LET'S GET MOVING

The time for debating the equitability of vehicle electrification, and waffling over whether or not to make investments in it, is behind us. Electric vehicles of all sizes, shapes, and applications are coming quickly, and utilities and their regulators need to be prepared to implement programs now that will transform the mobility marketplace, lest they find themselves uncomfortably behind the curve and suddenly facing the need to install expensive peaking generation or to upgrade a large number of distribution transformers. The rapid and unplanned adoption of air conditioning 50 years ago put grid operators in just such a position, and it could happen again now, only at a much larger scale and a much higher cost. It is absolutely critical to get right the methods and infrastructure for vehicle electrification from the start, with appropriate tariffs, well-planned charging infrastructure, and the ability to manage chargers either directly or through aggregators.

With careful planning and early intervention, the electric vehicle revolution can help optimize the grid and reduce the unit cost of electricity, while increasing the share of renewable electricity and reducing emissions

THE ROLE OF PILOTS AND DEMONSTRATIONS FOR EXPANDING EV INFRASTRUCTURE

In many parts of the U.S., EV adoption remains low and there is a dearth of data to inform EV charging infrastructure deployments and related policy decisions. Where this is the case, pilots and demonstrations offer an important opportunity to quickly build evidence that can inform future infrastructure deployments. Pilots also offer an opportunity to make lower-risk investments while rapidly deploying much-needed infrastructure.

However, pilots and demonstrations are not a panacea and they have their limitations. When used ineffectively or unnecessarily, pilots can delay important infrastructure investments or system enhancements, and yield little insight that would support scaling.

RMI recently investigated the best practices for utility pilots and demonstrations and shared our findings in our report *Pathways for Innovation: The Role of Pilots and Demonstrations in Reinventing the Utility Business Model.*[118] We identified the following best practices for utility pilots and demonstrations:

- Strategic Planning: Embrace a strategy for energy system transformation and craft a complementary road map for innovation.
- Design to scale: Design pilots and demonstrations to maximize learning and prepare for full-scale deployment.
- Organization: Create leadership support and accountability, dedicated resources, and cross-functional collaboration within the utility for effective innovation.
- Stakeholder engagement: Collaborate effectively across industry stakeholder groups to design and execute meaningful pilots.
- Cross-utility collaboration: Share best practices and lessons learned among utilities to accelerate effective innovation.

Each of these best practices is relevant to rapidly scaling the deployment of EV charging infrastructure to support an electrified transportation future. If pilots and demonstrations are designed well, the industry can test a range of promising and innovative approaches to integrating EV charging infrastructure for the benefit of customers, utilities, and the environment.

in both the electricity and transportation sectors. Without it, we could wind up with a lot of inefficient and expensive generation capacity with low load factors, a network of chargers that doesn't provide cost-effective and accessible support for EVs, higher costs, and unnecessary strife in regulatory proceedings as utilities, interveners, and regulators struggle to catch up to the challenge.

As we have demonstrated in this report, there is no single best approach to preparing for electric vehicles. Each U.S. state will have to answer key questions for itself, including:

- Who will guide charging infrastructure deployment: a market, central planners, public/private partnerships, or a legislature
- Who should install and own charging infrastructure
- What the role of regulators should be in guiding the infrastructure build-out
- How much of the total cost should be paid by drivers and private sector companies directly, and how much should be socialized
- How to design tariffs to reward charging behavior that provides grid services and absorbs low-carbon power generation
- Where to site charging stations so that they will be well used and produce enough revenue to more than cover their own costs, while still remaining useful as society eventually transitions away from personal vehicle ownership and toward ridesharing services.

One thing that all areas have in common, however, is that they need to start installing charging stations, and making sure that they do it in a well-planned, coordinated fashion. If your state or municipality is just beginning to install public charging stations, then well-designed pilot installations and demonstration projects are a low-risk way to get started. If your community has already done some pilot projects and collected some data to help identify the stations that will get the most use, then turn those insights into a more comprehensive plan and starting building charging stations in earnest. Look at the various types of site hosts—commuting rest stops, single-family homes, multiunit dwellings, workplaces, shopping areas—and understand how each one will have a different use pattern and will play a different role on the grid when the loads of charging stations are carefully managed. And for every charging station that is deployed, ensure that useful data can be gathered on it to help decision makers understand the value/risk proposition of vehicle electrification in their communities. By starting with pilot projects, gathering data as the charging network scales up, and using that data to guide subsequent deployments, we can plot a path toward a fully optimized system that serves the needs of the entire community, not just early EV drivers.

GL GLOSSARY

B1 all-electric sport utility truck © Bollinger Motors, LLC

GLOSSARY

BEV	battery electric vehicle
DCFC	DC fast charging
EVSE	electric vehicle supply equipment (charging equipment)
G2V	grid-to-vehicle
GHG	greenhouse gas
IOU	investor-owned utility
PEV	plug-in electric vehicle
POV	personally owned vehicle
PHEV	plug-in hybrid electric vehicle
RIM	ratepayer impact measure
TCO	total cost of ownership
V2G	vehicle-to-grid
SAEV	shared autonomous electric vehicle

AP

APPENDIX: ANALYSIS METHODOLOGIES

image © Rocky Mountain Institute

APPENDIX: ANALYSIS METHODOLOGIES

FLEET TOTAL COST OF OWNERSHIP

We calculated the total cost of ownership (TCO) for a fleet of 30 vehicles, operated for five years, driving 25,000 miles per year, for both internal combustion and electric vehicles. Resale value was not included, and an end-of-life value of $0 was assumed for both vehicle classes. The fleet TCO included capital costs, financing costs, insurance, fuel, maintenance, oil, and federal- and state-level tax incentives. Detailed assumptions are shown in Table 4.

TABLE 4

FLEET TOTAL COST OF OWNERSHIP ASSUMPTIONS

ASSUMPTION / CALCULATION	VALUE	UNIT
FLEET SIZE	30	vehicles
ANNUAL MILES DRIVEN	25,000	miles
EFFECTIVE ELECTRICITY COST – INCLUSIVE OF FIXED, DEMAND, VOLUMETRIC, AND DELIVERY FEES		
Xcel	$0.15	$/kWh
AEP	$0.14	$/kWh
Austin Energy	$0.16	$/kWh
Hawaiian Electric	$0.18	$/kWh
SCE	$0.20	$/kWh
GASOLINE PRICE		
Colorado	$2.30	$/gallon
Ohio	$2.18	$/gallon
Texas	$2.14	$/gallon
Hawaii	$2.98	$/gallon
California	$3.03	$/gallon
STATE TAX CREDIT		
Colorado	$5,000	$/vehicle
Ohio	$0	$/vehicle
Texas	$500	$/vehicle
Hawaii	$0	$/vehicle
California	$2,500	$/vehicle
ICE PURCHASE PRICE	$25,670	$/mile
EV PURCHASE PRICE	$36,500	$/mile
OIL (ICE ONLY)	$0.006	$/mile
TIRES	$0.004	$/mile
MAINTENANCE COSTS	$0.016	$/mile
DISCOUNT RATE	10%	%

COST OF CHARGING BY CHARGER TYPE

We calculated the cost (to the homeowner, employer, or DCFC site host) of charging an electric vehicle at home, at work, or on a public DCFC network, using the applicable tariff from Table 6 (residential for home, commercial for workplace, and retail or utility programs for DCFC). We then derived the equivalent cost per mile based on the assumptions listed in Table 5.

The homeowner's cost assumes that charging is conducted using a Level 2 wall-mounted charger on a separate meter.

The employer's cost assumes that workplace charging is conducted using a shared and managed bank of 25 Level 2 chargers on a separate meter with an aggregate maximum charge rate of 20 kW. We determined the maximum managed power by assuming that 15% of the daily miles driven per EV were charged at work, on average, and were distributed non-uniformly throughout the workday, based on state-specific TOU rates where applicable. Unmanaged workplace charging would result in a significant increase in peak demand and is not modeled here.

The EV owner's cost of fast public charging assumes that it is conducted on a 50 kW DCFC unit and is based on the available retail DCFC program in that area as described in Table 6. Retail rates for DCFC in states without a utility-specific DCFC program are based on EVgo's Flex charging program.

TABLE 5

ELECTRIC VEHICLE CHARGING ASSUMPTIONS

ASSUMPTION / CALCULATION	VALUE	UNIT
WORKPLACE AGGREGATED PEAK CHARGING RATE	20	kW
HOME PEAK CHARGING RATE	7.7	kW
DCFC PEAK CHARGING RATE	50	kW
CHARGING BREAKDOWN		
Home	80%	% of daily charging needs
Workplace	15%	% of daily charging needs
DCFC	5%	% of daily charging needs
On-peak charging (workplace and home) on TOU rate	5%	% of on-peak charging
Annual vehicles miles traveled	13,000	miles/year
EV fuel efficiency	3.5	miles/kWh
Vehicle battery capacity	60	kWh
ICE fuel efficiency	24	mpg

TABLE 6

UTILITY TARIFF SUMMARY

STATE	UTILITY	FLEET	WORKPLACE	RESIDENTIAL TOU	PUBLIC DCFC
California	SCE	TOU EV-4	TOU EV-4	TOU EV-1	EVgo Flex plan
Colorado	Xcel	Secondary General	Secondary General	Residential TOU Pricing	EVgo Flex plan
Hawaii	HECO	TOU J	EV-F	Schedule R TOU	EV-U pilot
Ohio	AEP	GS3	GS3	Residential ToD	EVgo Flex plan
Texas	Austin Energy	AE Secondary V2	AE Secondary V2	EV 360	Plug in Everywhere

COST OF CHARGING FOR PUBLIC DCFC SITE HOSTS

We developed two host-site DCFC utilization profiles, urban and corridor, and for each profile we created a low- and high-utilization scenario.

The urban site profile was derived from real DCFC utilization data in California on the EVgo fast charging network. Details are available in our report, *EVgo Fleet and Tariff Analysis*.[119]

The corridor site profile was created to represent the expected utilization that a highway DCFC network would achieve if the network were ubiquitous and EV owners refueled under the same refueling behaviors as ICE drivers do along highway corridors. It is important to note that the corridor utilization profile is theoretical and somewhat optimistic, because it is unlikely that this type of charging behavior would be realized without both a robust and ubiquitous corridor charging network and EVs with a standard 240-mile range.

CORRIDOR DCFC LOAD PROFILE

Figure 24 shows the low- and high-utilization scenarios for the corridor DCFC load profile. Vehicles are assumed to have a 60 kWh battery that begins each charging event with a 25% charge and ends with a 90% charge.

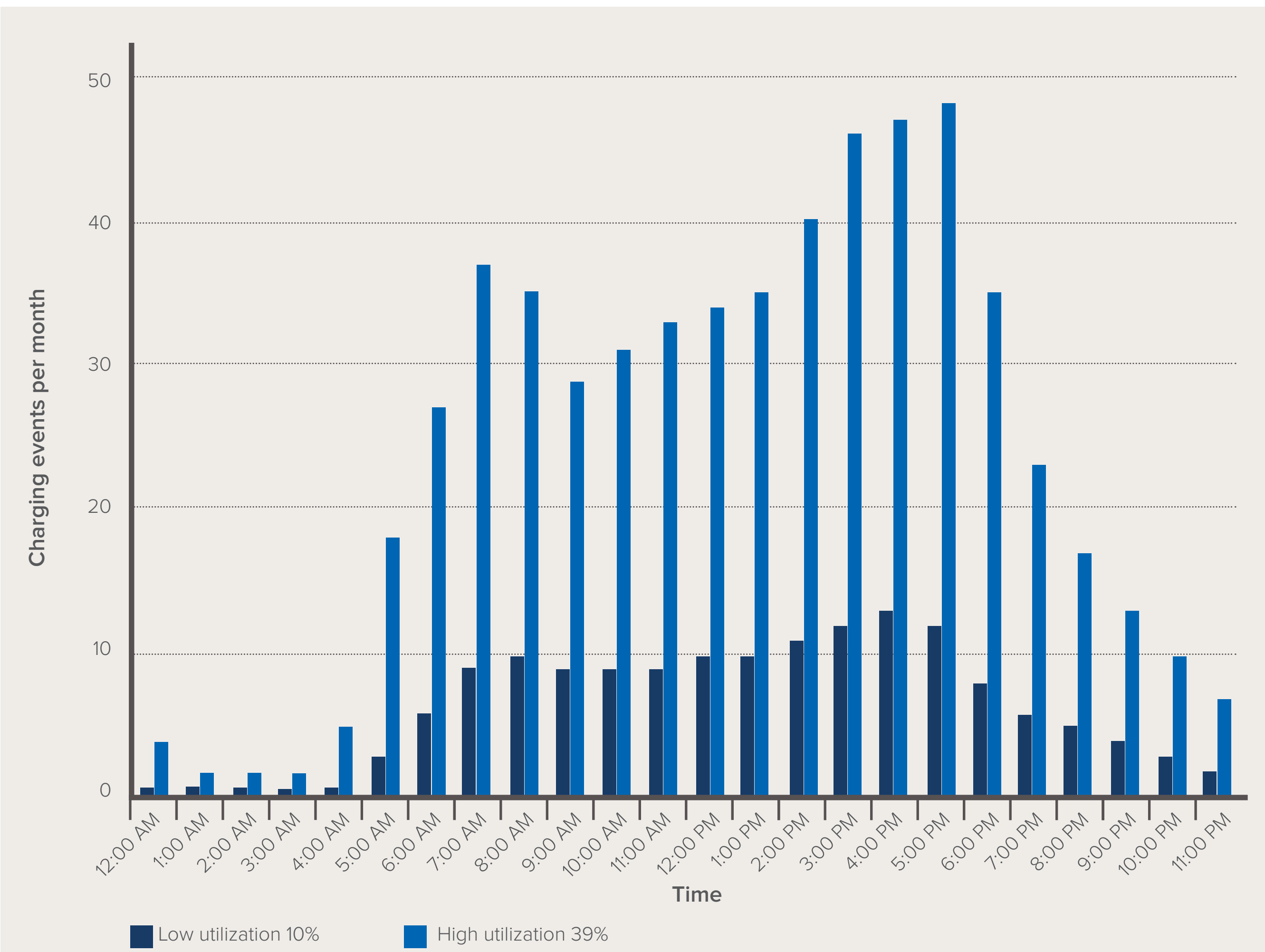
The low-utilization scenario assumes 156 charging events per month, with a total delivered energy of 5,938 kWh per month, representing a 10% utilization factor.

The high-utilization scenario assumes 580 charging events per month, with 22,539 kWh of energy delivered per month, representing a 39% utilization factor.

We calculated the timing and frequency of charging events using an idealized model based on actual volumetric traffic flows along interstates 91 and 95 in Massachusetts, with I-91 representing the low-utilization scenario and I-95 the high-utilization scenario. We assumed that a bank of DCFC chargers was available every 100 miles along each corridor, and that 1% of vehicles on the road were EVs.

FIGURE 24

CORRIDOR DCFC UTILIZATION PROFILE



URBAN DCFC LOAD PROFILE

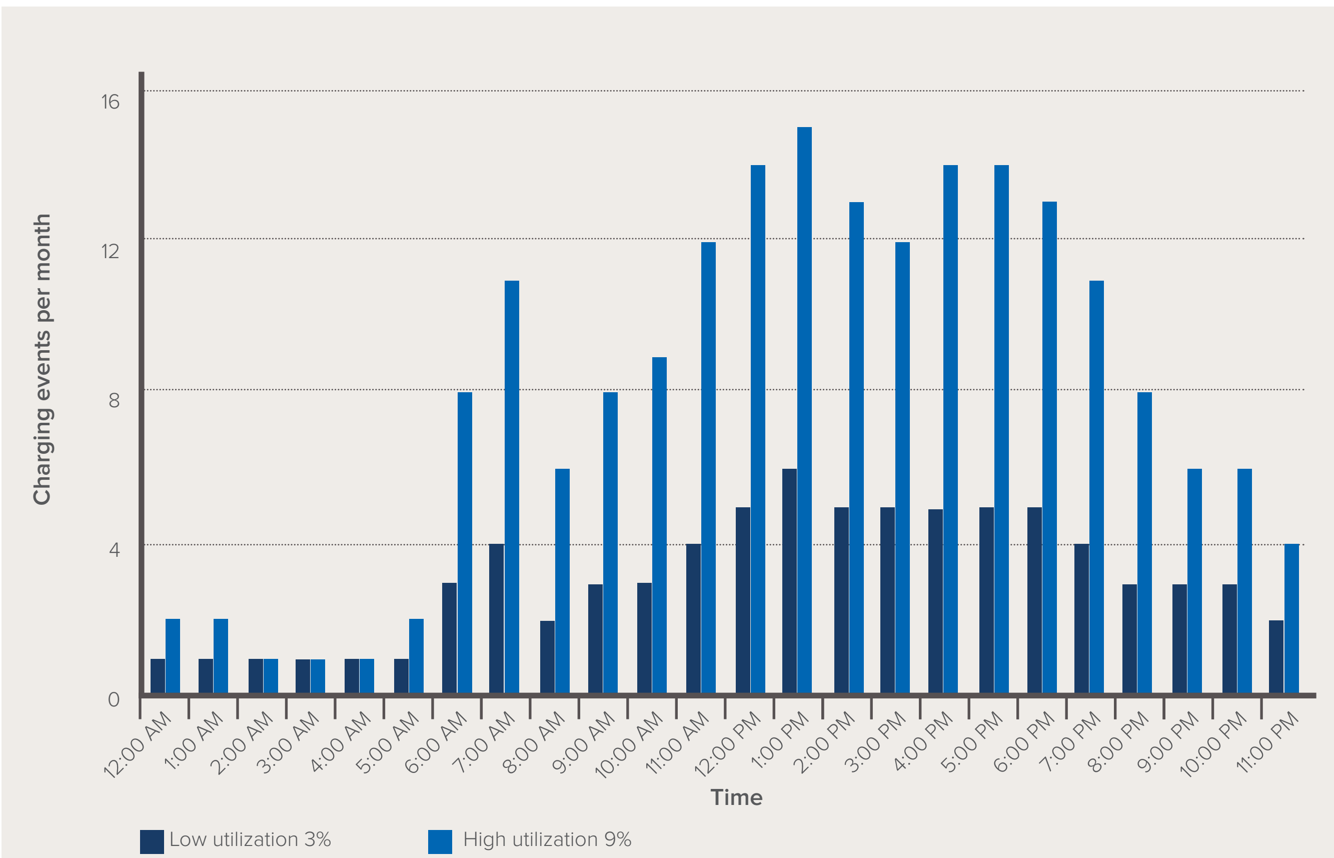
Figure 25 shows the low- and high-utilization scenarios for the urban load profile. The profiles were derived from our *EVgo Fleet and Tariff Analysis* report. Vehicles are assumed to have a 60 kWh battery that begins each charging event with a 40% charge and ends with an 85% charge.

The low-utilization scenario assumes 76 charging events per month, with 1,718 kWh of energy delivered per month, representing a 3% utilization factor.

The high-utilization scenario assumes 183 charging events per month, with 4,934 kWh of energy delivered per month, representing a 9% utilization factor.

FIGURE 25

URBAN DCFC UTILIZATION PROFILE



We calculated the cost (to the DCFC site hosts) of providing charging using the load profiles shown in Figure 25 and the applicable commercial tariff structures from Table 6. We assumed that each DCFC station had two ports, with a peak capacity of 100 kW per station. We assumed that each station is separately metered and draws a peak demand of 100 kW. Based on the monthly utility bill and number of miles charged in each scenario, we calculated the cost (to the site host) for delivering one mile of EV range. This cost represents the cost to the DCFC host site for electricity service only, and does not include other operational site costs.

Exhibit JRB-5

SUMMARY OF COSTS AND BENEFITS FROM LITERATURE

FIGURE 26

DETAIL OF STAKEHOLDER BENEFITS FOR EVS FROM THE LITERATURE

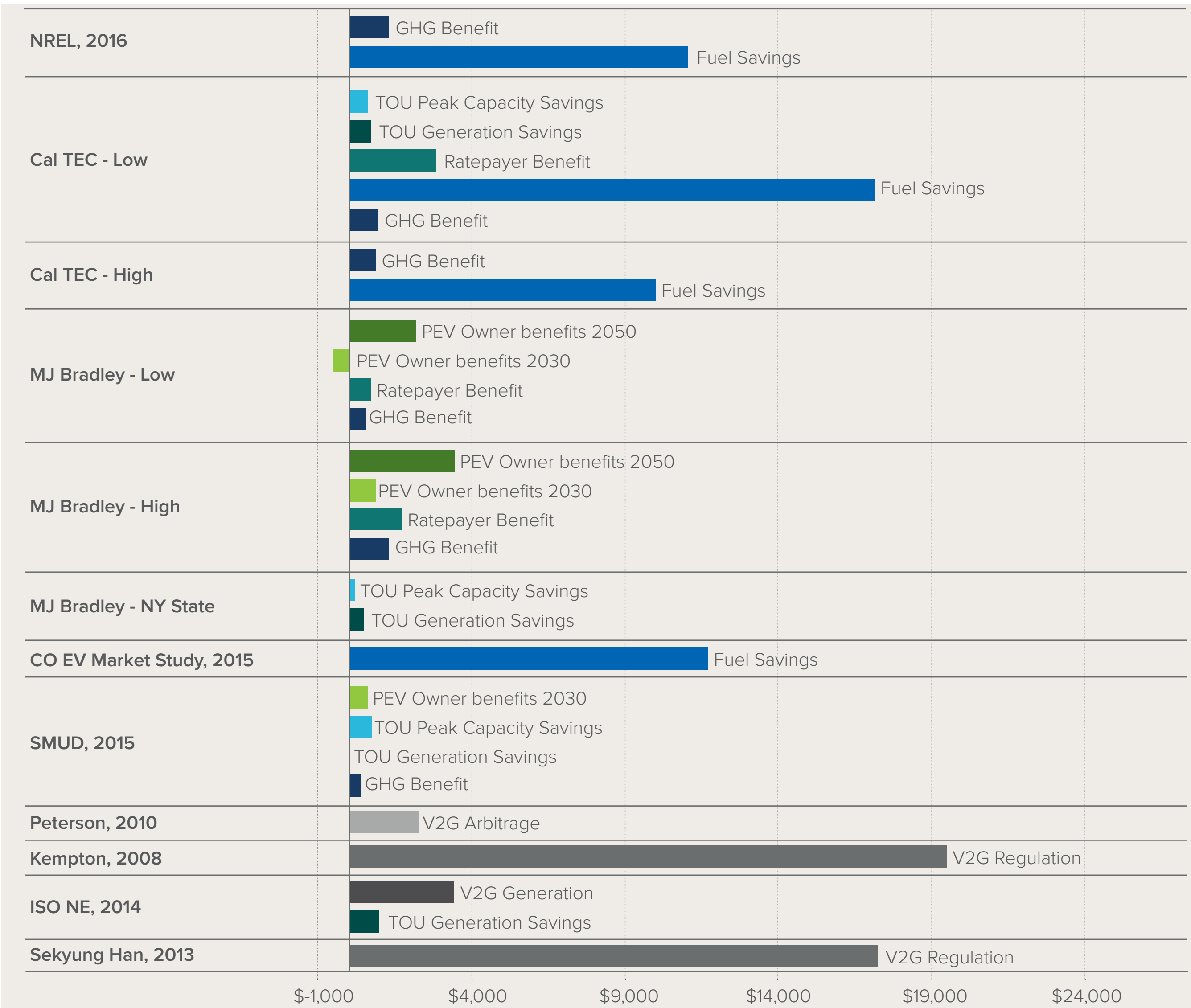


TABLE 7

TABULATED EV STAKEHOLDER BENEFITS FROM THE LITERATURE

	NREL, 2016	CAL TEC - LOW	CAL TEC - HIGH	MJ BRADLEY - LOW	MJ BRADLEY - HIGH	MJ BRADLEY - NY STATE	CO EV MARKET STUDY	SMUD, 2015	PETERSON, 2010	KEMPTON, 2008	ISO NE, 2014	ISO NE, 2014
GHG BENEFIT	$1,350	$1,033		$611	$1,294			$62				
FUEL SAVINGS	$10,700	$16,528					$11,249					
RATEPAYER BENEFIT		$2,788	$9,607	$744	$1,692							
TOU GENERATION SAVINGS		$764	$878			$477		$414			$995	
TOU PEAK CAPACITY SAVINGS		$661				$216		$738				
V2G REGULATION										$18,744	$3,068	$16,590
V2G ARBITRAGE									$2,186			
PEV OWNER BENEFITS *2030				-$370	$940			$697				
PEV OWNER BENEFITS *2050				$2,100	$3,380							

EN ENDNOTES

image © Rocky Mountain Institute

ENDNOTES

[1] Assumes U.S. EV sales growth of 32% per year, 13,500 miles/year, 3.5 mi/kWh, and $0.132/kWh.

[2] Patrick Hummel, et al., "UBS Evidence Lab Electric Car Teardown – Disruption Ahead?" UBS, May 18, 2017, https://neo.ubs.com/shared/d1ZTxnvF2k/.

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22830 Two Rivers Road
Basalt, CO 81621
www.rmi.org

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1214

In the Matter of:	**)**
Application of Duke Energy Carolinas,	**)**
LLC for Adjustment of Rates and	**)**
Charges Applicable to Electric Service	**)**
in North Carolina	**)**

DIRECT TESTIMONY OF
JUSTIN R. BARNES
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT JRB-6

I/A

PUBLIC VERSION

EVGO FLEET AND TARIFF ANALYSIS

PHASE 1: CALIFORNIA

BY GARRETT FITZGERALD AND CHRIS NELDER

AUTHORS & ACKNOWLEDGMENTS

Authors

Garrett Fitzgerald, Chris Nelder

** Authors listed alphabetically. All authors are from Rocky Mountain Institute unless otherwise noted.*

Contacts

Chris Nelder (cnelder@rmi.org)

Garrett Fitzgerald (gfitzgerald@rmi.org)

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Image courtesy of EVgo

About Rocky Mountain Institute

Rocky Mountain Institute (RMI)—an independent nonprofit founded in 1982—transforms global energy use to create a clean, prosperous, and secure low-carbon future. It engages businesses, communities, institutions, and entrepreneurs to accelerate the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables. RMI has offices in Basalt and Boulder, Colorado; New York City; Washington, D.C.; and Beijing.

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Public direct current fast chargers (DCFC) are anticipated to play an important role in accelerating electric vehicle (EV) adoption and mitigating transportation sector greenhouse gas (GHG) emissions. However, the high cost of utility demand charges is a significant barrier to the development of viable business models for public DCFC network operators.

With today's EV market penetration and current public DCFC utilization rates, demand charges can be responsible for over 90% of electricity costs, which are as high as $1.96/kWh at some locations during summer months.[i] This issue will be compounded by the deployment of next-generation fast-charging stations, which are designed with more than two 50 kW DCFC per site and with higher-power DCFC (150kW or higher).

As state legislators begin to craft legislation defining the role of utilities in deploying, owning and operating electric vehicle charging stations (EVSE) and other supporting infrastructure, it is critical that utility tariffs for EV charging support, rather than stifle, the shift to EVs. Utilities, their regulators, and EV charging station owners and operators must work together to provide all EV drivers—especially those without home and workplace charging options—access to reliable EV charging at a rate competitive with the gasoline equivalent cost of $0.29/kWh.[ii] Put another way, it should be possible for DCFC operators to sell power to end-users for $0.09/mile or less, while still operating a sustainable business.

This project analyzed data from every charging session in 2016 from all 230 of EVgo's DC fast charging stations in the state of California. From that data, we developed demand profiles for eight common types of site hosts, and analyzed the components of EVgo's costs based on the utility tariffs the charging stations were on.

We also created a workbook modeling tool that EVgo could use to test the effect that different tariffs would have on its network of charging stations within the territory of the three major California investor-owned utilities (IOUs): Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and Pacific Gas & Electric (PG&E). To provide context for this modeling, we created four scenarios describing the possible future evolution of the EV and public charging markets. These scenarios were narrative in nature, and mainly served as conceptual guides to future cost modeling.

After modeling how different current and future tariffs affect the utility bills for each type of site where EVgo's DCFC are located, and how those bills might look under the four scenarios in the future, we developed a critique of the various tariffs and some recommendations for future EV-specific rate design efforts.

We concluded that, in order to promote a conducive business environment for public DCFC charging stations like EVgo's, tariffs should have the following characteristics:

- Time-varying volumetric rates, such as those proposed for SDG&E's Public Charging Grid Integration Rate (GIR). Ideally, these volumetric charges would recover all, or nearly all, of the cost of providing energy and system capacity. An adder can be used to recover excessive costs for distribution capacity, but only costs in excess of the cost of meeting the same level of usage at a uniform demand rate, and ideally such an adder would be something the customer can try to avoid. The highest-cost periods of the time-of-use (ToU) tariff should coincide with the periods of highest system demand (or congestion) to the maximum practical degree of granularity.
- Low fixed charges, which primarily reflect routine costs for things like maintenance and billing.

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[i] Based on summer rates at EVgo's lowest-utilization SDG&E Freedom Station, Las Americas (bill date of June 28, 2016),
[ii] Assumes 32 mpg, $3/gallon of gas, 0.32 kWh/mile

- The opportunity to earn credit for providing grid services, perhaps along the lines of a solar net-metering design.
- Rates that vary by location. “Locational marginal pricing” is conventionally a feature of wholesale electricity markets, reflecting the physical limits of the transmission system. But the concept could be borrowed for the purpose of siting charging depots, especially those that feature DCFC, in order to increase the efficiency of existing infrastructure and build new EV charging infrastructure at low cost. This could be done, for example, by offering low rates for DCFC installed in overbuilt and underutilized areas of the grid, particularly for “eHub” charging depots serving fleet and ridesharing vehicles.
- Limited or no demand charges. Where demand charges are deemed to be necessary, it is essential that they be designed only to recover location-specific costs of connection to the grid, not upstream costs of distribution circuits, transmission, or generation.

Our analysis shows that the new EV-specific tariffs proposed by SDG&E and SCE in their SB 350 Transportation Electrification applications would have far more stable and certain costs than the tariffs currently available in their territories, and would meet the objective of delivering public charging to end-users for less than $0.09/mile, in all four scenarios. This is primarily due to the lower or non-existent demand charges outlined in the new tariffs.

We show that reducing or eliminating demand charges for the commercial public DCFC market, as these new tariffs do, is consistent with good rate-design principles and helps California to achieve its social objectives. We suggest that recovering nearly all utility costs for generation, transmission, and distribution through volumetric rates is appropriate for tariffs that apply to public DCFC, and that recovering some portion of those costs from the general customer base would be justifiable because public DCFC provide a public good. Finally, we offer some additional suggestions for how EVgo might reduce the cost of operating its network, beyond switching tariffs.

FLEET AND TARIFF ANALYSIS

The purpose of this analysis was to determine the key factors that contribute to the electricity costs of EVgo's network of DCFC in California; what alternatives may be available to EVgo to reduce those costs; and to provide some guidance that may be useful for future rate design discussions.

Analysis of Current EVgo Fleet Usage in California

In the first part of the analysis, RMI and EVgo collaboratively explored the question: What are the demand profiles and energy consumption rates of EVgo's existing California DCFC network, and how do those profiles vary across different types of host sites?

EVgo provided data representing all fast charging sessions that occurred on its network of 230 DCFC in California in 2016. Key data included:

- Start time of session
- Length of session
- kWh consumed per session
- Host address and name

From this data, RMI created an hourly load profile for each host site. These profiles were used to identify usage trends and behaviors that are typical for particular types of host sites.

A sample monthly load profile is shown in Figure 1. It shows the energy sold per month (measured in kWh) and the monthly peak demand (measured in kW), for a DCFC located in Northern California. It demonstrates a large (up to 70%) variation in energy sales from month to month, and a relatively small (16%) variation in peak demand each month. This type of variation suggests a potentially unprofitable charging station, because the commercial electricity tariffs that these charging units are on will typically derive a significant portion of the bill from monthly demand charges (where the variation was small) while EVgo's revenue would primarily derive from the number of charging sessions and kWh consumed (where the variation was large).

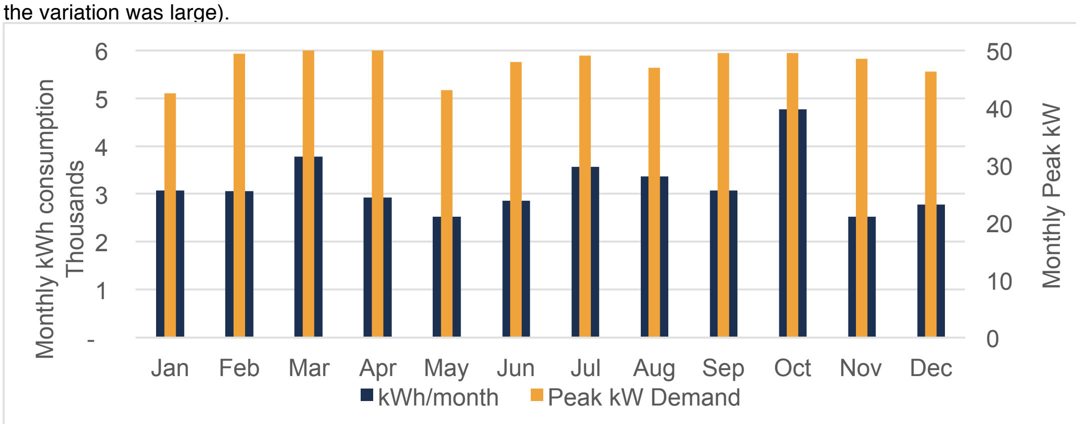

Figure 1: Monthly energy use and peak demand of an individual EVgo host site

A sample daily profile is shown in Figure 2. It shows the average utilization of an individual charger for each hour of the day. (Utilization is defined as the percentage of an hour that an EV is connected to the DCFC.) Hourly utilization is a useful way to understand when EV chargers are being used, and is of increasing importance as utilities are beginning to offer new EV-specific tariffs featuring ToU rates.

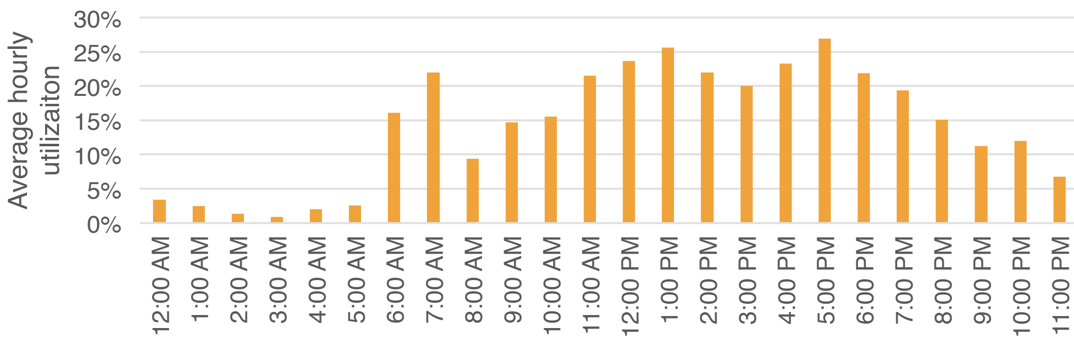

Figure 2: Hourly utilization rates of an individual EVgo host site

HOST CATEGORIZATION

We then grouped the various types of host sites into eight categories, based on the type of commercial activity associated with the host facility, and calculated a set of aggregate annual utilization and performance metrics for each category. This allowed us to identify utilization characteristics for each host type, and explore how monthly operational costs varied by host type. The summary results of this analysis, shown in Table 1, showed that charger utilization, average power, and energy consumption all vary significantly by the host type.

Host Category	*Peak kW*	*Avg kW*	*Avg kWh*	*Length (min)*	*# of sites*
Grocery	44	25	7.8	18	75
Mall	45	23	9.4	24	34
Other	44	27	8.2	18	11
Dealership	44	32	11.5	22	31
Retail	44	24	5.7	14	58
Gas Station	45	30	9.3	18	6
Gov't/School	41	26	8.3	19	13
Hotel	43	29	10.2	21	2

Table 1: Annual DCFC utilization and performance metrics by site host type

Exploring the relationships between the charging rate (kW), energy consumption (kWh), and charge duration offered some useful insights into how customers use these chargers. For example:

- Customers charging at retail locations tend to arrive with a higher state of charge (which causes a low average charging rate) AND are connected for a shorter duration (suggesting that they are just topping off their batteries, or charging opportunistically).
- Customers charging at car dealerships are arriving with a lower state of charge (which causes a higher average charging rate) AND are connected for a longer duration (suggesting that they have made a special trip to the dealership to get a full charge).

Exploring customer behavior as a function of host type was outside of the scope of this project. However, customer behavior and, more importantly, customer responsiveness to ToU price signals will be of critical importance in the design of both commercial DCFC tariffs and the pricing structures charging companies like EVgo offer to their customers. We explore these issues later in this report.

Regardless of the type of host, the DCFC utilization profile resembles the load profile of the California Independent System Operator (CAISO) system (the wholesale bulk power system in California), with low use in the early morning, increasing use throughout the day, and then a peak between 5 p.m. and 9 p.m. This is not surprising considering that customers typically use public DCFC opportunistically, when they're running errands and making other routine trips in the afternoon or after-work hours.

EV and EVSE Growth Scenarios

Before proceeding with modeling EVgo's current and future electricity costs, we created four scenarios describing how EV adoption and DCFC deployment might proceed in the future to provide context for the analysis. In the workbook model, these scenarios mainly serve as conceptual guides; they are not meant to be empirically derived.

ASSUMPTIONS

These assumptions apply to all four scenarios.

1. Time horizon: 10 years (2017–2027)
2. Incremental change only—no major technology breakthroughs, radical policy changes, etc.
3. Stable-to-slow-growth (3% or less compound annual growth rate[1]) for the U.S. economy
4. Industry standard DCFC power rate is 50 kW at start of scenario, 150 kW by 2020, and 300 kW by 2027. The average EV can accommodate the same rate of charging in those years.
5. Vehicle battery capacity ranges from 30–60 kWh in 2017, and 60–90 kWh from 2020 onward.[i]
6. Autonomous vehicles only become a factor after 2020 in all scenarios.

SCENARIOS

The main differences between the first three scenarios are the levels of EV adoption and corresponding distributed DCFC deployment. In the fourth scenario, autonomous vehicles become dominant rather quickly, and DCFC deployment is concentrated in charging hubs designed to serve fleets of shared vehicles, rather than being widely distributed.

Scenario 1: BAU, slow EV growth

A default business-as-usual (BAU) path in which current trends continue more or less unchanged. Personally owned vehicles remain dominant and EV penetration continues to follow today's moderate growth rates. Deployment of autonomous vehicles after 2020 is negligible, so those vehicles are not a factor in siting DCFC.

- EVs on the road in the US in 2027: 1.4 million, representing a compound annual growth rate (CAGR) of about 10%
- California falls short of its goal of having 1.5 million zero-emission vehicles (ZEVs) on the road by 2025. Instead it keeps its current market share of about half the U.S. EV fleet and achieves 700,000 EVs by 2027.
- Most charging is done at workplaces and homes using Level 1 or Level 2 chargers.

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[i] At 100 kWh, a vehicle would have a roughly 400 mi. range, which should be sufficient for most users' purposes. Therefore, we assume it would not be cost-effective to build vehicles with more than a 100 kWh capacity. Indeed, battery capacity may actually *decline* as DCFC chargers become more widely available, and it becomes less necessary to be able to drive long distances without recharging.

- There is a perceived need for DCFC services, but actual use of public DCFC is still quite limited at the end of the scenario period.
- Wireless charging does not get traction.
- Utility tariffs for EVs are still a very uneven landscape nationally, with California still the most progressive state, and most other states having no special EV tariffs.
- Vehicles are idle 95% of the time, making them available to provide demand response and other grid services.

Scenario 2: BAU, fast EV growth

BAU is still the main context and personally owned vehicles remain dominant, but EVs experience much faster growth. Deployment of autonomous vehicles after 2020 is negligible and they are not a factor in siting DCFC.

- EVs on the road in the US in 2027: 4.1 million (CAGRs accelerate from ~10% in 2017 to 35% in 2027)
- California meets its goal of having 1.5 million ZEVs on the road by 2025.
- DCFC for public access, workplaces, and heavily trafficked highway corridors are broadly available by 2027 and meet 30% of EV electricity consumption (kWh), but it's all still wired EVSE (not wireless). "Charging valets" are commonly used to move vehicles in and out of the charging bays, and their pay is regarded as a loss leader by the shopping malls, workplaces, and other sites where the chargers are located.
- Most utilities have offered EV-friendly charging tariffs by 2027, and the majority of chargers are on those tariffs.
- Some utilities buy grid services from EV aggregators and fleets using Level 1 and Level 2 chargers, but DCFC only sell demand response to utilities.

Scenario 3: Personal EVs gain real market share as wireless charging and autonomous EVs get traction

Personally owned vehicles remain dominant as EVs experience very fast growth. Autonomous vehicles become popular from 2020 onward and become a factor in siting DCFC.

- EVs on the road in the US in 2027: 10 million.
- California far exceeds its goal of having 1.5 million ZEVs on the road by 2025; it actually has 5.0 million by 2027.
- Over the scenario period, charging has begun to migrate to high-speed wireless induction chargers, which by 2027 are popping up everywhere: in parking spots, at stoplights, at workplaces, etc. Charging transactions are automated and billing is handled by a common payment processor (Visa, Stripe, a blockchain payment processor, or the like).
- Autonomous vehicles can go park themselves elsewhere when they're done charging to free up the charger for the next vehicle.
- Only about 20% of charging load is now met by Level 1 or Level 2 chargers at workplaces and residences, so their capacity to sell grid services to utilities is limited. The other 80% of charging load is met by ubiquitous DCFC, which can supply most vehicles with an 80% full charge in 15 minutes.
- Nearly all EVSE are on an EV-specific ToU tariff with local utilities.

Scenario 4: Fast autonomous EV growth leads to a MaaS future

EVs experience fast growth throughout the scenario period and autonomous vehicles gain a majority of market share by 2021, completely upending the normal vehicle market. By the end of the scenario period, autonomous vehicles are around 15% of all vehicles, as projected in Figure 3 below. Most of the autonomous vehicles are fleet vehicles and ride-hailing vehicles as mobility-as-a-service (MaaS) becomes commonplace. Personal vehicle ownership is in decline and most new vehicle sales are for fleet and ridesharing purposes.

- EVs on the road in the US in 2027: 41 million
- California has ~10 million ZEVs on the road by 2025, most of which are ride-sharing vehicles.

- Personal vehicle ownership falls sharply after 2020. By the end of the scenario period, sales of EVs have surpassed sales of internal-combustion engine (ICE) vehicles.
- DCFC are ubiquitous, meeting about 85% of EV electricity consumption. Many individual EV owners don't ever charge at home.
- Autonomous vehicles serve 30% of the total personal vehicle-miles-traveled (VMT) demand. Most of the autonomous EVs recharge at eHubs in a price-responsive manner when electricity costs are lowest.
- Distributed DCFC deployment may be topping out by the end of the scenario period, as hub-based charging of fleet vehicles becomes the dominant mode.

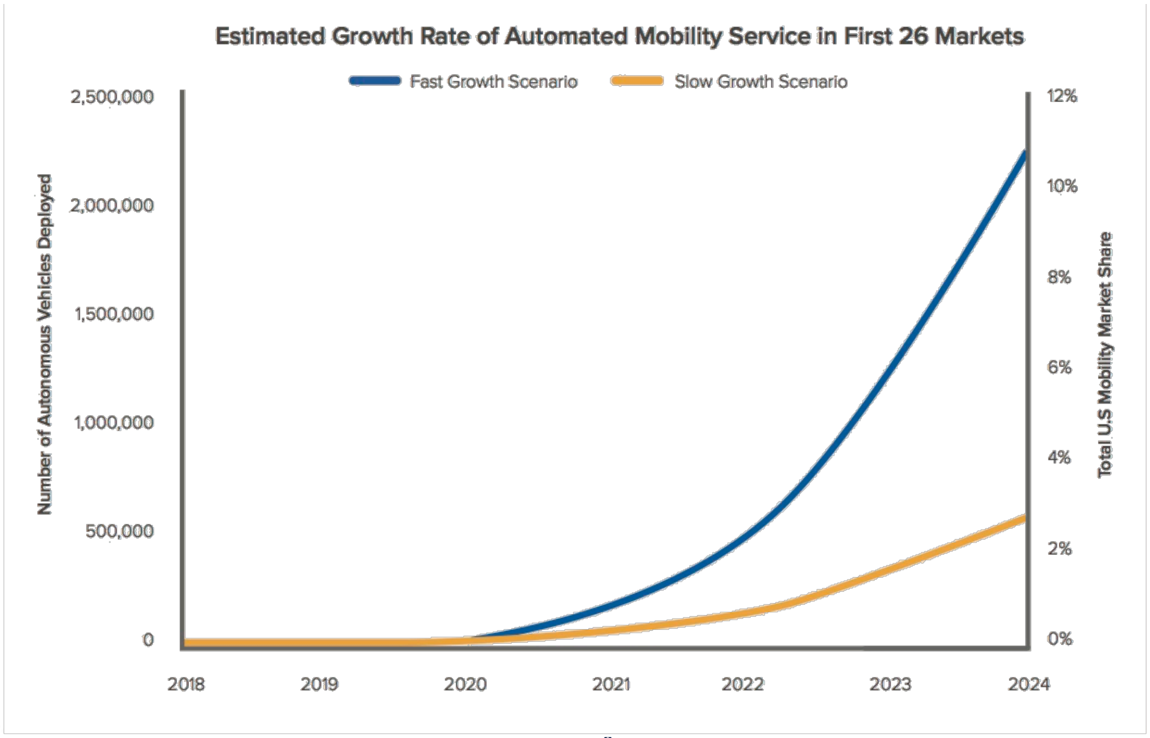

Figure 3 Mobility-as-a-service scenario. Source: RMI 2016, *Peak Car Ownership*[2]

Based on these scenario narratives, we created a simple model for EV deployment in California, shown in Figure 4. This EV model was integrated into the DCFC modeling workbook.

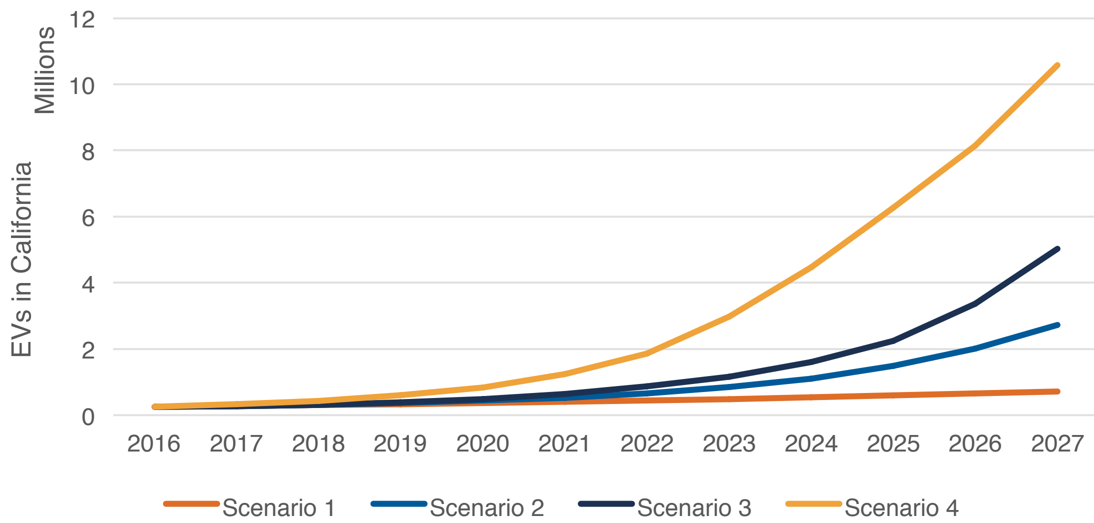

Figure 4: California EV deployment in the scenarios

HOW WE REPRESENTED THE SCENARIOS IN THE WORKBOOK MODEL

Although the scenarios were narrative in nature, and mainly served as conceptual guides to future cost modeling rather than being empirically represented, we did need to represent them numerically in the workbook to test how different tariffs would affect EVgo's fleet in the future.

The model is designed to determine the cost of operating DCFC under different tariffs and scenarios. The key cost determinants are:

- The number of kilowatt-hours consumed in a month
- When those kilowatt-hours are consumed (if under a ToU rate)
- The single hour of a month in which the highest demand occurred (if the tariff includes demand charges).

To determine those numbers for each scenario, we manually programmed the model with the following assumptions for three modeling years within the ten-year scenario period:

- The beginning (2017)
- Near the middle (2020, chosen because that year is often cited in policy targets and technical literature)
- The end (2027).

All scenarios began with the same data in 2017, derived from EVgo's actual data and other sources.

The following summary of the parameters used in the model is for illustrative purposes only; see the workbook for complete details.

Parameter	***Value in 2017***	***Value in 2027***
Average DCFC power (kW)	24	100–200
Peak power of a charging session (kW)	50	300
Vehicle battery capacity (kWh)	40	60–90
Charge to be filled per charging session (%)	30	30–50

Number of EVs in California	250,000	713k–10.6M
Annual VMT per vehicle (miles)	13,000	13,000–30,000
Efficiency (EV miles per kWh)	4	4
DCFC market share (% of total kWh charged with DCFC)	3	20–85
DCFC per 100 EVs in California	0.003	0.3–0.6

Table 2: Manually defined parameter values in the scenario model

From these initial values, we calculated:

Parameter	***Value in 2017***	***Value in 2027***
Average charging time (minutes)	30	8–19
Average charge per session (kWh)	12	27–63
Total kWh charging per month in CA (kWh)	77m	193m–6.6B
Number of public DCFC available	700	2k–63k
Average utilization per DCFC (%)	8	19–31

Table 3: Calculated parameter values in the scenario model

We then manually defined the shape of the load for the DCFC under each scenario in each of the three modeling years to notionally fit the narrative descriptions, by setting the percentage of total usage in each of the 24 hours of the day. Based on the load shape that emerged from this programming, we manually identified the hour of the day in which the peak monthly demand occurred.

Here is a brief description of our reasoning in selecting these load shape values.

2017

All scenarios are identical and represent a typical charger on the EVgo network today.

2020

Scenario 1 – Exactly the same load shape as in 2017, because utilities are slow to offer EV-specific ToU tariffs in Scenario 1, so drivers would not receive any particular price signals to charge differently than they did in 2017. However, overall usage increases slightly to reflect more EVs on the road.

Scenario 2 – DCFC utilization increases slightly across California. Overall utilization is slightly higher than in 2017 due to more EVs on the road and better siting and management by DCFC operators. Overall charging load is starting to shift towards midday in response to some ToU rates.

Scenario 3 – DCFC utilization is higher overall as some autonomous vehicles and charging valets increase the availability of DCFC. More of the load is shifted to midday than in Scenario 2 because more intensive charging management allows the vehicles to optimize their DCFC usage more closely to ToU rates with super off-peak periods in the midday.

Scenario 4 – The load shape is essentially the same as for Scenario 3 but with slightly higher overall utilization as fleet and ridesharing vehicles make up a greater part of the EV population. Total kWh consumed is substantially higher than in Scenario 3. A very significant increase in DCFC availability (from 0.003 to 0.7 per 100 vehicles) has kept utilization rates modest, but the DCFC fleet has grown by more than an order of magnitude.

2027

Scenario 1 – The load shape remains the same as in 2017, reflecting the lack of utility ToU rates under this business-as-usual scenario. The utilization rate is the same as in 2020 but the total kWh consumed has doubled due to more vehicles and chargers in the field.

Scenario 2 – The load shape is substantially similar to what it was in 2020, but with a bit more charging at midday as drivers take advantage of ToU rates to charge at their workplaces or during their lunch breaks.

Scenario 3 – The load shape is strongly shifted to midday in response to ToU rates, because autonomous vehicles can drive themselves to go find a charger when they are idle.

Scenario 4 – The load shape is highly optimized to charging at midday as fleet and ridesharing vehicles take advantage of super off-peak periods under ToU rates. However, charging dips slightly during times when demand for rides would be highest: during the morning and evening commutes, at lunchtime, and at the end of the evening as bar, restaurant, and entertainment patrons go home. Utilization rates are still modest but a vastly expanded DCFC fleet (roughly as many DCFC in 2027 as there are gasoline pumps in California today[3]) now serves 85% of total EV demand.

EV Rate Design

Having analyzed the use patterns of EVgo's DCFC fleet, developed an economic modeling workbook, and created scenarios to contextualize the economic analysis, we still needed to understand the current tariffs that the DCFC are under, and the new EV-specific tariffs that the California utilities have proposed.

In this part of the analysis, we begin with a very brief review of rate design theory, then move on to a discussion of the new proposed tariffs. Finally, we summarize the findings of our economic modeling of the various rates, and consider the likely implications for DCFC rate design in California in the future.

RATE DESIGN THEORY

EVs have only recently become a sufficiently significant type of load to warrant special tariffs, and so there is not as yet an established practice for EV rate design. However, in light of expected growth in EV ownership, unique charging attributes of EVs, and resulting effects on electricity demand, specific attention is now being paid to designing rates for EVs. Designing these well will be very important to realizing the goals of individual EV owners, fleet owners/operators, utilities, and society at large. Because it is about EVgo's DCFC fleet, this section focuses on rates for commercial DCFC operators, and leaves aside rates for residential customers charging EVs.

To understand the contemporary thinking on tariff design for commercial DCFC, and the anticipated trajectory of EV-specific tariff design in California, we examined the Transportation Electrification Plans submitted by the three California IOUs in January 2017, pursuant to SB 350 and California Public Utility Commission (CPUC) ruling R.13-11-007, "Order Instituting Rulemaking to Consider Alternative-Fueled Vehicle Programs, Tariffs, and Policies."[4]

California has roughly one-half of the nation's EV fleet, the most aggressive policies and targets in the nation for EV and charging infrastructure deployment, and utility programs specifically designed around EV-grid integration. On account of these structural conditions and the state's history of leadership on environmental and vehicle regulations, California's approach to DCFC tariff design may emerge as the utility industry "best practice" that other states will emulate.

In its Transportation Electrification Application,[5] SDG&E reiterates the CPUC's ten Rate Design Principles, as follows:

Cost of Service	·	Rates should be based on marginal cost;
	·	Rates should be based on cost-causation principles;
	·	Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals;
	·	Incentives should be explicit and transparent;
	·	Rates should encourage economically efficient decision-making;
Affordable Electricity	·	Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost;
Conservation	·	Rates should encourage conservation and energy efficiency;
	·	Rates should encourage reduction of both coincident and noncoincident peak demand;
Customer Acceptance	·	Rates should be stable and understandable and provide customer choice; and
	·	Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.

Table 4: CPUC rate design principles

Of these principles, the ones pertaining to cost of service are the most relevant to tariffs for DCFC. How utilities incur specific costs, and then recover those costs through tariffs, is the heart of the question for tariffs that apply to DCFC. Conservation principles are also important because, as we will explain, DCFC-friendly tariffs would also try to reduce overall demand (especially demand coincident with system peaks or local distribution-area peaks).

SUMMARY ANALYSIS OF NEW TARIFFS PROPOSED BY SCE AND SDG&E

A brief summary of the new tariffs that were proposed by SCE and SDG&E in their Transportation Electrification Proposals and which would be applicable to EVgo's chargers follows. (PG&E did not submit any new EV-specific tariffs in its Transportation Electrification Plan, so its rates are not discussed here.)

SDG&E

The San Diego Gas & Electric (SDG&E) application[6] identifies "six priority review projects and one standard review residential charging program, all of which are designed to accelerate widespread transportation electrification in SDG&E's service territory, while maximizing grid efficiency with proper rate design." Of these projects, two have tariffs that could conceivably apply to EVgo's DCFC network:

- A Commercial Grid Integration Rate (GIR) applicable to the Fleet Delivery Services project, in which charging infrastructure will be installed at six locations to be used by electric fleet and delivery vehicles, such as those operated by UPS. This project would encourage charging at times that are beneficial to the grid and include a mix of Level 2 and DCFC charging stations. All of the chargers would be owned and operated by SDG&E.[7]
- A Public Charging GIR, applicable to participants in the Green Taxi/Shuttle/Rideshare project, which includes charging infrastructure, vehicle incentives, and a tariff aimed at the taxi, ridesharing, and shuttle bus market. This project would support up to four EV taxis, four electric shuttles and 50 transportation network company

(rideshare) EVs by deploying up to five grid-integrated charging facilities (one DCFC and two Level 2 EVSE each). All of the chargers would be owned and operated by SDG&E.[8]

To understand the underlying theory of rate design and cost recovery, it is worth examining SDG&E's explanation about why it has constructed these new tariffs the way it has.

SDG&E identifies the following objectives for its proposed tariffs:

1. To encourage economically efficient decision-making;
2. To encourage reduction of both coincident and noncoincident peak demand;
3. To provide a rate design that encourages cost-effective grid integrated charging solutions for EV customers;
4. To avoid cross-subsidies;
5. To base rates on cost causation; and
6. To examine alternative rate design.

SDG&E notes that in order to satisfy these objectives and the CPUC rate design principles, tariffs must **send accurate price signals**, which are **based on marginal costs and cost-causation principles**. (We would also note that the CPUC principles equally encourage conservation, energy efficiency, and demand management.)

SDG&E proposes to require participants to take service on its alternative GIR rate structures based on these cost-causation principles in order to accurately reflect costs.

The following table maps the typical tariff components to their cost-recovery justifications and their roles in the proposed GIR tariffs.

Charge Component	***Cost Recovered by the Charge***	***Component in Proposed GIR Tariffs***
Fixed or monthly charge ($/month)	Routine costs of having an interconnected customer, such as meter reading and billing	**Grid Integration Charge** ($/Month) Based on customer's max annual demand (kW), to recover all basic customer costs and 80% of distribution-demand costs
Peak demand charge ($/peak kW)	Costs of maintaining **system capacity** sufficient to meet peak demand (independent of energy usage) in excess of the cost of meeting below-peak demand	**Dynamic Adder – Commodity** ($/kWh – Top 150 hours of **system peak**)[9] Based on **commodity** peak pricing, to recover 50% of generation capacity costs
Noncoincident demand charge ($/noncoincident kW)	Costs of maintaining **circuit capacity** sufficient to meet the combined demands of customers on the circuit (independent of energy usage) in excess of the cost of meeting the same level of usage at a uniform demand rate	**Dynamic Adder – Distribution** ($/kWh – Top 200 hours of **circuit peak**)[10] Based on **distribution** peak pricing, to recover 20% of distribution demand costs Plus: Grid Integration Charge ($/Month per max kW), to recover distribution capacity investment

Energy charge ($/kWh at time of use)	Costs of procuring energy at a given point in time, plus the costs of distribution that would be incurred if all usage were at a uniform rate of consumption	**Hourly Base Rate** ($/kWh) Based on a variety of generation and transmission costs

Table 5: SDG&E charges, cost-recovery intents, and tariff components

Commercial GIR tariff

To support the policy objective of vehicle electrification specifically, SDG&E proposes a declining four-year discount on the monthly Grid Integration Charge for the Commercial GIR tariff. The cost of the discount would be recovered from all customers.

Rates for the new Commercial GIR tariff would be as follows:

Charge type	***Amount***
Grid Integration Charge[11]	Based on kW of maximum annual demand, with a declining discount over the first four years. When the discount expires in year five, EVgo DCFC might incur: · $522.37/mo. for up to 20 kW · $882.55/mo. for 20–50 kW · $1,458.86/mo. for 50–100 kW · $2,539.41/mo. for 100–200 kW
Hourly Base Rate	$0.096/kWh + CAISO day-ahead hourly rate
Dynamic Adder – Commodity	$0.50535/kWh
Dynamic Adder – Distribution	$0.18656/kWh

Table 6: Illustrative commercial GIR tariff charges

PUBLIC CHARGING GIR TARIFF

Because there is no single dedicated customer for public chargers, there is no Grid Integration Charge. Instead, some distribution-related costs are recovered through the Hourly Base Rate.

Rates for the new Public Charging GIR tariff would be as follows:

Charge type	***Amount***
Grid Integration Charge	N/A
Hourly Base Rate	$0.13871/kWh + CAISO day ahead hourly rate
Dynamic Adder – Commodity	$0.50535/kWh
Dynamic Adder – Distribution	$0.18656/kWh

Table 7: Illustrative commercial GIR tariff charges

ANALYSIS OF SDG&E'S PROPOSED TARIFFS

Although the new rates proposed in SDG&E's Transportation Electrification application are specifically targeted to the select projects SDG&E is proposing, in which it would install, own, and operate the charging infrastructure, the application also states, "While SDG&E provides these rate proposals as part this TE Application, SDG&E proposes not to limit the applicability of the proposed GIR to participants of SDG&E's TE proposals, and instead proposes that they be made available to all customers."[12]

The Commercial GIR is evidently targeted to delivery trucks and other fleet vehicles that can recharge overnight at a central charging depot, so it does not seem to apply to EVgo's network. However, it's not obvious whether EVgo could own chargers that would be available to delivery vehicles and be eligible the Commercial GIR. If any of EVgo's charging stations were to be used primarily by delivery trucks or other fleet vehicles, this tariff would pose a challenge to business model viability due to its high fixed Grid Integration Charges (unless the charging stations had very high utilization rates).

Allocating distribution-related costs through the fixed Grid Integration Charge would make it impossible for EVSE operators like EVgo to avoid those charges by smart charging (to avoid adding loads to the system peaks). It applies a high fixed monthly cost to every charging station, irrespective of that station's utilization rate. Applying this tariff to EVgo's charging stations would be undesirable.

The Public Charging GIR is aimed at high mileage taxi, shuttles and transportation network company (rideshare) electric vehicles that travel high-use transportation corridors. It is certainly within reason to expect that these vehicles, particularly ones operated by ridesharing companies like Uber, may use EVgo's network of DCFC in equal measure to the ones proposed in the SDG&E project. Other than ownership, there does not appear to be any qualitative difference between the public chargers in SDG&E's proposed Green Taxi/Shuttle/Rideshare project and the ones owned and operated by EVgo.

If EVgo's network of charging stations were to be considered eligible for the Public Charging GIR, it could be a good option for EVgo. As SDG&E explains, the Public Charging GIR does not apply the fixed Grid Integration Charges because there is no single dedicated customer for public chargers. Instead, it recovers a share of the distribution-related costs through the Hourly Base Rate. In theory, EVgo chargers on the Public Charging GIR could not only shift charging to low-cost, off-peak hours by various means, but also pass on peak CAISO pricing to customers who use the charging stations through visual price displays.

On an energy-only basis, the wholesale power supply cost of operating an EVgo charger on the Public Charging GIR might work out to around $0.048 per mile of charge. Whereas a consumer driving an ICE vehicle equivalent to a Nissan LEAF might expect to pay on the order of $0.094 per mile to refuel with gasoline. To a first approximation, then, on the Public Charging GIR, EVgo might have nearly a 100% margin to work with between its cost of utility service and the consumer's ICE refueling cost.[13] EVgo could use that margin to offset its site costs and equipment costs.

However, the "dynamic adders" (a form of Critical Peak Pricing charge) on the Public Charging GIR could amount to a worst-case annual cost of nearly $5,000 per year per charger. If EVgo could avoid or reduce its demand during the top 150 system hours and 200 circuit hours per year, for example by employing a stationary battery system to supply the power during those hours, or by throttling the chargers during those hours, or by raising its retail prices during those hours, or by some other means, those charges could be avoided and the tariff would be quite desirable. Since the peak hours that incur the dynamic adder fees are posted a day in advance, it should be practical for EVgo to pass along those costs to customers for charging during those hours.

If the worst-case dynamic adder costs were incurred, the effect on final cost would vary depending on several factors. For example: If they were amortized across the entire year, it would add $414 per month in costs. Assuming an average of 10 kWh of charge per session, that would affect the cost of the charger as shown in the following table.

Charging sessions per month	*Final wholesale cost to EVgo*
300	$0.092
600	$0.070
900	$0.063

Table 8: Estimated cost/mile scenarios under SDG&E Public Charging GIR

Even under the worst-case scenario and 300 sessions per month, the Public Charging GIR appears to be a more attractive option than the tariffs that typically apply to the class of Medium/Large Commercial & Industrial ("M/L C&I") Customers who have monthly demand peaks over 20 kW. Under the AL-ToU Commercial rate, EVgo's charging stations incur very high demand charges, which are used to recover distribution costs, transmission costs, and commodity costs. As a result, EVgo's stations under SDG&E's AL-ToU tariff are the costliest of all of its stations in California, regardless of utilization rate.

SCE

Southern California Edison (SCE), in its Transportation Electrification Plan, proposes three new, optional commercial tariffs for EVs, in addition to maintaining its existing ToU-EV-3 and ToU-EV-4 tariffs. Both the old and the new EV-specific tariffs are available for modeling and comparison in the modeling tool workbook deliverable.

All of the new rates are based on a revised ToU schedule that "will offer more accurate price signals to reflect system grid conditions, consistent with the Commission's recent guidance in this area." This ToU schedule, shown below, has the lowest-cost off-peak periods in the middle of the day, when Southern California's solar systems are producing power. This is nearly the inverse of a more traditional ToU schedule, and reflects the changing nature of the grid. (Before solar became a major midday power source in California, the most expensive "peak" pricing on a ToU schedule was always in the middle of the day, when demand was highest. Now Southern California frequently has enough solar power to drive prices to their lowest levels in the midday, making it the "super-off peak" period in the winter months, and the "off peak" period in the summer months of the proposed new ToU schedule.)

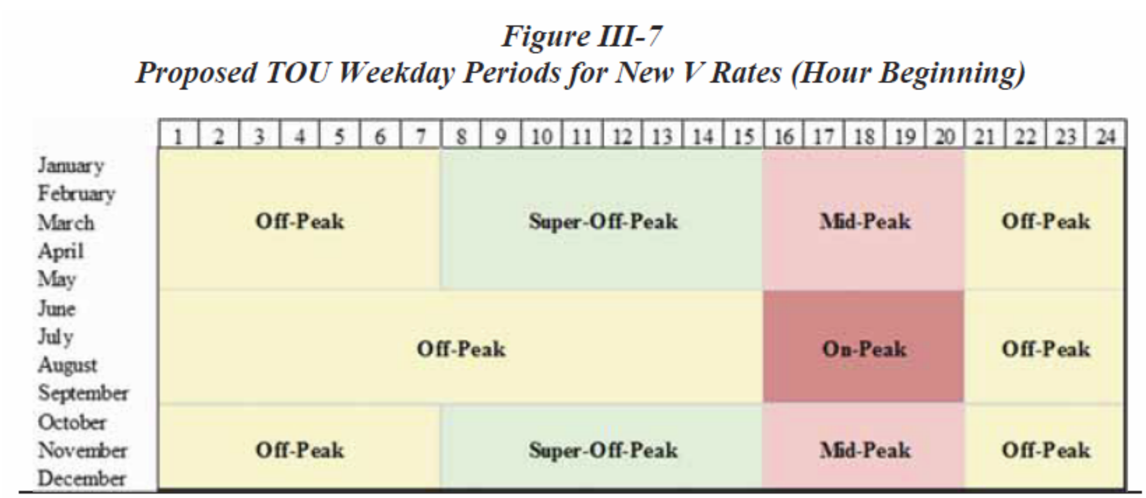

Figure 5: SCE's proposed ToU schedule for new EV tariffs. Source: Southern California Edison[14]

ANALYSIS OF SCE'S PROPOSED TARIFFS

Of the three new tariffs, the ToU-EV-8 tariff seems most likely to apply to EVgo, as it applies to customers with a monthly maximum demand between 21 and 500 kW.

SCE describes the benefits of the new EV tariffs as: “(a) reduced distribution-related demand charges relative to the current EV and non-EV rates; (b) attractive volumetric rates during daytime super-off-peak periods and overnight; and (c) lower summer season charges to mitigate seasonal bill volatility.”

Importantly, to promote EV adoption, the new EV tariffs will suspend monthly demand charges during a five-year introductory period, after which SCE will phase in demand charges for a five-year intermediate period. During this intermediate period, the demand charges would collect an increasing share of distribution capacity-related costs, up to 60%, while the remaining 40% of distribution capacity costs will be collected via TOU energy charges. As the demand charges increase, the energy charges will decrease. Beginning in the eleventh year, the demand charges will be collecting 60% of distribution capacity costs and 100% of transmission capacity costs, and will have climbed to their full level, but SCE claims that the demand charges will “still be lower than what new EV customers would pay on their otherwise applicable (non-EV) commercial rates today.”

The way demand charges are calculated would also change. Under its existing EV tariffs, “time-related demand charges” (TRD) are assessed on a time-of-use basis during the on- and mid-peak periods in a month. Under the new tariffs, “facilities-related demand charges” (FRD) would be calculated based on the maximum demand in a month, irrespective of its coincidence with the system peak. This change would make it more difficult for EVgo to pass on its time-varying costs to its charging station customers, or to reduce demand charges by encouraging customers to charge at times when grid power costs are lower. It also seems to contradict the intention of the demand charges, which is to recover SCE’s capacity-related delivery costs.

The anticipated annual average bills for a medium-duty load (21 kW – 500 kW) under the proposed ToU-EV-8 tariff would be significantly lower than the current tariff alternatives for the first 10 years, but then approach the anticipated cost of being on the ToU-EV-4 tariff, as shown in SCE’s table below.

Current ToU-GS-3	***Current ToU-EV-4***	***Future ToU-GS-3***	***Introductory New ToU-EV-8 Rate***	***Proposed Final ToU-EV-8 (Year 11)***
$93,208	$82,040	$89,997	$63,343	$75,995

Table 9: Anticipated annual average bills under various SCE EV tariffs

Analysis of current EVgo fleet electricity costs in California

With all of the components of the analysis now in place, our next step was to proceed to understanding the cost of current and future tariffs on EVgo’s fleet, and develop some recommendations.

COST STRUCTURE OF CURRENT CALIFORNIA EVSE FLEET UNDER CURRENT RATES

To understand how EVgo’s DCFC incur electricity costs, we developed a flexible Excel-based economic model to calculate the cost of operating the DCFC at each host type under various utility tariffs.

We modeled the typical daily load profiles for each host type and the actual utilization rates of the DCFC under several tariffs, including four tariffs the DCFC are on currently in each utility service territory, and the two new tariffs proposed by SCE and SDG&E.

Table 10 shows an illustrative total monthly electricity bill that a typical site with two DCFC would incur at each host type under these rates.

Category	*Host Type A*	*Host Type B*	*Host Type C*	*Host Type D*
Utilization	*15%*	*8%*	*8%*	*4%*
***SCE ToU EV 4** (actual)*	$1,933	$1,817	$1,762	$1,682
***SCE ToU EV 8** (proposed)*	$808	$648	$569	$461
***SDG&E AL-ToU Commercial** (actual)*	$3,313	$3,219	$3,178	$3,114
***SDG&E Public Charging GIR** (proposed)*	$501	$329	$255	$138
***PGE A-6 ToU** (actual)*	$484	$322	$260	$150
***PG&E A-10** (actual)*	$1,318	$1,197	$1,147	$1,065

Table 10: Monthly utility bill by rate and host type

This analysis demonstrated that tariffs with high demand charges and low energy charges (EV 4 and AL-ToU) show minimal variation in the total bill across a wide range of DCFC utilization, while tariffs with smaller or no demand charges show a much wider range in total electricity bill.

It also demonstrated that DCFC with identical load profiles may incur widely varying utility bills, depending on the tariff. For example, operating a DCFC at a Host Type D with an average utilization of only 4% would cost EVgo $150 per month on the PGE A-6 ToU rate, but would cost $3,114 on the SDG&E AL-ToU rate—20 times more.

Both findings demonstrate the same point: that tariffs without demand charges more accurately reflect cost causation, whereas those with demand charges would be burdensome to any public DCFC, regardless of utilization. This is problematic because it is the very nature of underutilized or newly installed DCFC that the station can experience very low monthly kWh consumption and relatively high peak demand.

Table 11 shows the fraction of the total utility bill that demand charges make up under each tariff.

Tariff	*Host Type A*	*Host Type B*	*Host Type C*	*Host Type D*
***SCE ToU EV 4** (actual)*	70%	75%	77%	81%
***SCE ToU EV 8** (proposed)*	0	0	0	0
***SDG&E AL-ToU Commercial** (actual)*	88%	91%	92%	94%
***SDG&E Public Charging GIR** (proposed)*	0	0	0	0
***PGE A-6 ToU with Option R** (actual)*	0	0	0	0
***PG&E A-10** (actual)*	67%	73%	76%	81%

Table 11: Demand charge bill fraction under various rates

COST STRUCTURE OF CURRENT DCFC OPERATION IN CALIFORNIA UNDER ALTERNATIVE/PROPOSED EV RATES

Using the economic model and applying actual utilization data[i] of a DCFC deployed in California, we compared how the cost of operation could change if the proposed EV tariffs are adopted and applied to EVgo's DCFC network. Table 12 and

[i] Hourly utilization profile of a typical grocery host site with a monthly kWh consumption of 2,764 kWh and a monthly peak demand of 88 kW

Table 13 show the component costs of SCE and SDG&E utility bills for the current and proposed EV tariffs. In both cases, the total bill would be drastically reduced (by between 50% and 80%) under the new proposed tariffs, primarily because SCE proposes waiving demand charges for the first five years of its tariff, and SDG&E proposes to waive the grid integration charge for its public chargers. Eleven years after its introduction, when demand charges are fully incorporated into the SCE EV-8 tariff and energy costs are adjusted downward, the total bill is still 25% lower than today's TOU EV-4 rate.

SCE	***Fixed***	***Energy***	***Demand***	***Total***
TOU EV4	$220	$278	$1,362	$1,938
TOU EV 8 without demand charges	$330	$478	$0	$808
TOU EV 8 with demand charges in year 11	$330	$368	$792	$1,490

Table 12: Utility bill for existing and proposed SCE EV tariffs

SDG&E	***Fixed***	***Energy***	***Demand/Dynamic***	***Total***
AL-TOU	$116	$279	$2,545	$2,941
Public GIR	$0	$452	$115	$567

Table 13: Utility bill for existing and proposed SDG&E tariffs

POTENTIAL COST OF FUTURE FLEET UNDER VARIOUS RATES BY SCENARIO

Our final step was to explore how EVgo's electricity costs could evolve over the next decade under various rates for each scenario. The scenario analysis forecasts the total monthly bill for a site with two DCFC being billed under the three most common existing commercial rates (SDG&E AL-TOU, PG&E A-10, and SCE TOU EV-4) and two proposed EV-specific tariffs (SDG&E Public GIR and SCE TOU EV-8) offered by the IOUs. We forecast monthly electricity costs that EVgo's chargers would incur in 2017, 2020, and 2027 for each of the four scenarios.

Figure 6 shows how these tariffs compare under the scenario analysis, in terms of the average cost that EVgo would incur per mile of charge that they deliver to the end customer. This cost-per-mile metric is an appropriate basis for comparison because the utilization of the DCFC and the number of customers each one serves can vary so widely from scenario to scenario.

I/A

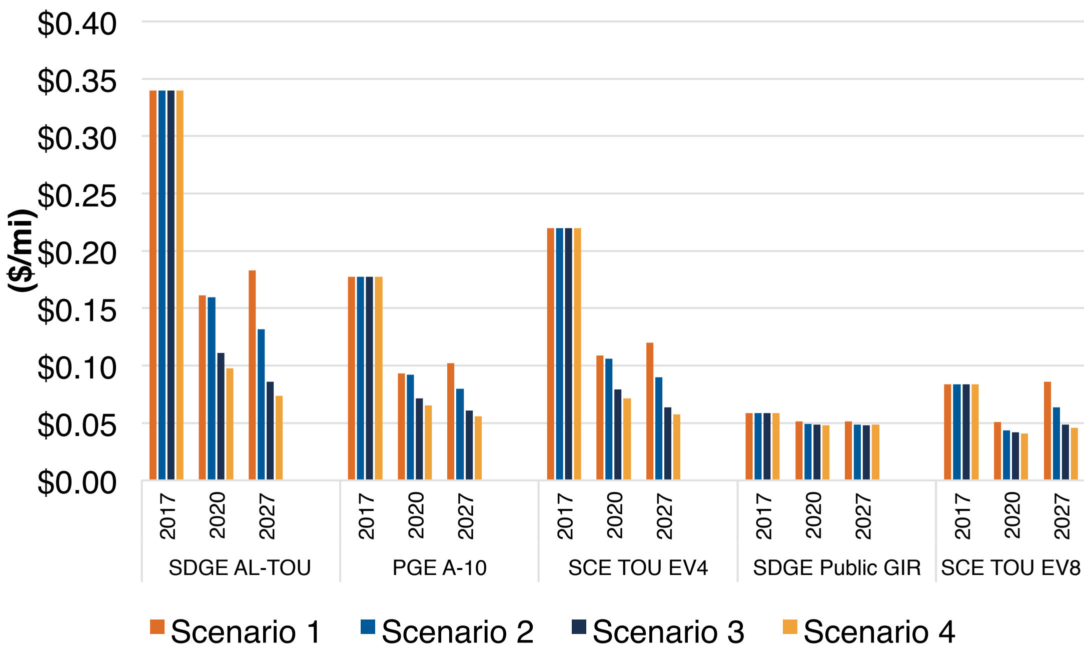

Figure 6: EVgo's cost per mile to deliver one mile of EV charge for existing and proposed EV tariffs

In all scenarios, the cost per mile of charge delivered to customers would decrease over time, primarily as a result of increased and optimized charger utilization. However, the costs would vary widely, from $0.05/mile to $0.35/mile, and would be highly dependent on the rate of EV and charging station deployment represented in the scenarios.

This analysis clearly shows that the new EV-specific tariffs proposed by SDG&E and SCE would have far more stable and certain costs, and would meet the objective of delivering public charging to end-users for less than $0.09/mile, in all four scenarios. This primarily owes to the lower or nonexistent demand charges outlined in the new tariffs. (*Nota bene*: The cost per mile under the SCE TOU-EV8 tariff declines from 2017 to 2020 because demand charges are waived during that period, then it increases again in 2027 as demand charges are phased in.)

Recommendations

It is clear from our analysis that demand charges, more than other rate components, are the primary reason why it is economically challenging to operate public DCFC profitably in California. As our analysis of chargers on the SDG&E AL-ToU Commercial rate clearly demonstrates, demand charges make up the vast majority of the bill, regardless of the charger's utilization. The fact that the proposed new EV-specific tariffs eliminate demand charges for a period of time, or for "Option R" charger installations, which also feature on-site renewable energy generators, indicates that the utilities understand this issue.

Switching to the proposed SDG&E and SCE tariffs that rely on dynamic adder charges rather than more conventional demand charges seems to solve many of the problems inherent in the existing tariffs. These new tariffs better align the utility costs with charges paid by EVgo, and could produce a fairer outcome in which it is possible for DCFC operators like EVgo to obtain a flatter, more predictable cost structure.

The question that remains is whether or not the new tariffs that the California IOUs have proposed can enable a profitable business for public DCFC charging companies, and whether there may be alternative approaches to rate design that would be more attractive.

PUBLIC DCFC RATE DESIGN THEORY/BEST PRACTICES

For a good guide to rate design theory in general, we recommend *Smart Rate Design for a Smart Future*.[15] It contains a good deal of material that may be useful to EVgo. But here are some condensed thoughts about tariffs for public DCFC like EVgo's in particular.

In theory, demand charges are assessed in such a way as to reflect the actual incremental capacity costs that the distribution utility incurs at peak times of the day, over and above the cost of capacity to serve off-peak demand. In practice, however, the structure of a tariff, including demand charges, often reflects other utility and social priorities as well, and the way that costs are recovered from various customer classes is not always consistent or reflective of cost causation.[16]

Traditional demand charges for small-to-medium commercial customers were never designed for a business like EVgo's, which has little control over when customers use its chargers, and which sees widely varying utilization rates across a heterogeneous network of chargers in widely varying locations and site types. In short, EVgo's network of chargers looks and behaves nothing like a large commercial or industrial facility, but it's being billed as if each location is a separate commercial facility.

The CPUC decision of December 2014 on a rate design proposal to include an Option R tariff in PG&E territory supports this reasoning. That case concerned how demand charges were used to recover peak-related capacity costs for solar customers, but the reasoning should apply equally to DCFC loads, which are also sporadic-use customers with a great deal of diversity. As the CPUC's decision argued:

> The first line of argument is that the collection of coincident peak related capacity costs on the basis of customers' highest single intervals of demand does not reflect the diversity benefit of multiple customers' solar output, and net loads on PG&E's system, changing by different amounts at different times….Stated differently, total coincident demand will never equal the sum of each customer's highest recorded demand during a given time period because of the variability of millions of customers' demands.[17]

It is also true that the local infrastructure needed to serve DCFC, particularly dense groups of chargers in an "eHub" configuration as imagined in Scenario 4, would be non-trivial and location-specific, and so would meet the criteria for recovery on a customer-specific basis. Customer-specific charges for customer-specific costs to connect to the grid can cover this local transformer and service line cost. But this cost recovery should not reach upstream of the immediate distribution connection to the broader distribution circuit costs (substation, transmission, and generation), all of which would be more equitably recovered on a ToU energy basis so that shared-capacity customers share costs, and continuous-capacity customers are not subsidized.

Although utilities may argue that high demand charges, adders, and fixed charges based on maximum demand, like SDG&E's Grid Integration Charge and SCE's TRD, are justified methods of recovering the costs of capacity investments, these approaches also allow off-peak loads to free-ride on the system capacity paid for by on-peak users. If total system demand were uniform across all hours, and there were thus no "peak" to trigger demand charges, there would still be extensive generation, transmission, and distribution capacity costs to be paid by all customers. Therefore, it's reasonable to argue that demand-based approaches amount to a shifting of system capacity costs onto customers with peaky demand profiles, and put an undue cost burden on those who may happen to have very brief and occasional demand spikes, like DCFC owners. To avoid such a cost-shift, system capacity costs should be recovered via energy sales, not separate demand-based charges. By this rubric, SDG&E's recovery of a high percentage of distribution capacity costs through the Grid Integration Charge, and SCE's recovery of transmission costs through its TRD, would be considered regressive approaches and would be discouraged. Those costs should be primarily recovered through ToU energy rates.

For tariffs that apply to public DCFC, demand charges for distribution circuit and upstream costs should be deemphasized—or better, eliminated. If demand charges must be a feature of tariffs for EVs, then those charges should be time varying and reflect actual system costs at a given time, in keeping with the principle of sending accurate price signals based on marginal costs. That way, if customers like EVgo are able to reduce their demands on the system's transmission and distribution capacity by charging vehicles at times when there is spare grid capacity, they should be able to reduce their costs for making that effort. Likewise, customer-specific demand costs, such as the transformer and service drop, can be recovered via a fixed fee like a grid integration charge, but the circuit costs should not; those should be recovered in ToU energy charges to assure that sporadic-demand customers who can share capacity get the cost-saving benefits of that sharing.

Beyond such fine points of rate design theory, it may make sense to allocate the cost of EV infrastructure more broadly across the entire customer base, because promoting EV adoption is a societal goal that California has explicitly established, and public DCFC deliver a public good. This is what SDG&E proposes to do for the "discount" on the monthly grid integration charge component of its Commercial GIR tariff. Low-income discounts, renewable energy incentives, and spreading the costs of providing full system reliability and meeting peak demand across the customer base are other examples of how some portion of actual costs are routinely socialized rather than being recovered entirely through a specific tariff. As the authors of *Smart Rate Design for a Smart Future* put it: "Regulators will need to determine if the public benefit of providing an infant-industry subsidy to EV charging is consistent with the public interest."[18]

Considering that owning and refueling an EV is already cheaper than owning and refueling a conventional ICE vehicle in many cases, and seems destined to only become more so, the continued advance of EVs against the existing ICE regime should be a relatively uncontroversial assumption. If we assume that EVs will continue to gain market share on their way to a near-total eclipse of the existing ICE vehicle regime—particularly if the future belongs to ride-sharing services provided by autonomous electric vehicles as imagined in Scenario 4—then socializing some part of the costs of building universally-available charging infrastructure might be justified.

Further, demand charges were invented in an era when a consuming commercial or industrial facility was only ever just that—a consumer. As RMI elucidated in its 2016 report, *Electric Vehicles as Distributed Energy Resources*,[19] and as both SDG&E and SCE have acknowledged and piloted to various degrees, what we should be aiming for is a future in which EVSE doing "smart charging" can supply a variety of services back to the grid, in addition to consuming energy from the grid.

Accordingly, best-practice rate design for EVs would feature not only time-varying tariffs that reflect the actual cost of energy provisioning and delivery at a given time (and eventually, place), but also the ability of EVSE to *reduce* the need for investments in distribution capacity by providing services like demand response, as well as the need to invest in capacity to supply those same EVSE. However, as currently conceived, demand charges act more like a calculator that can only add.

In summary, to promote a conducive business environment for public DCFC charging stations like EVgo's, tariffs should have the following characteristics:

- Time-varying volumetric rates, such as those proposed for SDG&E's Public Charging GIR. Ideally, these volumetric charges would recover all, or nearly all, of the cost of providing energy and system capacity. An adder can be used to recover excessive costs for distribution capacity, but only costs in excess of the cost of meeting the same level of usage at a uniform demand rate, and ideally would be something the customer could try to avoid. The highest-cost periods of the ToU tariff should coincide with the periods of highest system demand (or congestion) to the maximum practical degree of granularity.

- Low fixed charges, which primarily reflect routine costs for things like maintenance and billing.
- The opportunity to earn credit for providing grid services, perhaps along the lines of a solar net-metering design.
- Rates that vary by location. "Locational marginal pricing" is conventionally a feature of wholesale electricity markets, reflecting the physical limits of the transmission system. But the concept could be borrowed for the purpose of siting charging depots, especially those that feature DCFC, in order to increase the efficiency of existing infrastructure and build new EV charging infrastructure at low cost. This could be done, for example, by offering low rates for DCFC installed in overbuilt and underutilized areas of the grid, particularly for "eHub" charging depots serving fleet and ridesharing vehicles
- Limited or no demand charges. Where demand charges are deemed to be necessary, it is essential that they be designed only to recover location-specific costs of connection to the grid, not upstream costs of distribution circuits, transmission, or generation.

A SOCIAL OBJECTIVE APPROACH

The preceding discussion attempted to use the framework of traditional rate-design theory and existing rate proposals to identify a viable path for public fast-charging companies like EVgo. But perhaps a more unconventional approach is worth considering.

To begin with, we should recognize that the societal objective should be to create a business opportunity for EV charging companies like EVgo to earn a reasonable profit by providing a valuable service and maintaining universally available charging equipment in serviceable condition. That is not currently the case.

To achieve this objective directly, we could design a tariff by working down from a cost that will be attractive to consumers, rather than by building up from the cost basis of the utilities. Based on our simple calculations above, this approach might target a cost to the EV end-user of no more than nine cents per mile, in order to maintain the cost advantage of EVs over ICE vehicles. From that nine-cent-per-mile target, one could deduct a reasonable profit margin for the charging companies, and then set the result as the cost ceiling for a tariff that applies to public DCFC owners. Whatever missing revenue there may be between the revenue potential of that tariff and what is deemed to be the actual cost of service could be recovered from the general customer base on a cost (not cost-plus) basis only, to reflect the fact that there are numerous EV-to-grid value streams that remain to be recognized in the tariffs, including the nebulous, yet real, value of enabling greater renewable energy penetration.

Should the state of the art in EV rate design evolve in the future, and make it possible to quantify and compensate the various value streams in the EV-grid interaction more discretely, a more sophisticated approach to EV tariffs could be devised. But at the present time, recognizing the great importance of California's societal goals embodied in the hopes for much faster EV adoption, the emerging nature of the underlying EV and telematics technologies, and the difficulty of the existing tariff regime for DCFC providers, a tariff along these lines can strike an appropriate balance between the theory and the practice of EV rate design, while supporting established policy objectives and design principles.

HOW TO MODERATE EVGO'S COSTS

If possible, the most straightforward option for EVgo to reduce its public DCFC costs would be to switch to the Public GIR tariff in SDG&E territory, and the TOU EV-8 tariff in SCE territory, as depicted in Figure 6. Switching to these tariffs could result in a bill reduction of up to 80% for DCFC in SDG&E territory, and between 25–50% for DCFC in SCE territory. Our modeling suggests that under these new tariffs, EVgo could potentially run those DCFC profitably while meeting the objective of delivering public charging to end-users for less than $0.09/mile. However, these tariffs are only proposed at this point, so whether switching to these tariffs is actually an option for EVgo is unknown at this time.

In the absence of tariff options for DCFC that substantially reduce or completely eliminate demand charges, the next best option might be for EVgo and other EVSE companies to adopt the concept of surge pricing and pass along the high demand charges and adders to their customers, where possible, to allow the utility's price signal to influence when and where electricity is used on the grid, as such charges are intended to do.

In SDG&E territory, it may be possible for EVgo to hedge against critical peak pricing events that trigger the dynamic adders of ToU rates by paying a fixed monthly Capacity Reservation Charge (CRC).[20] We did not model this option in this study, but it could be worth exploring with SDG&E.

It may also be possible for EVgo to get consolidated billing from the utilities based on the loads of all charging stations on the utility's system, at least for the generation and transmission cost components. Under such an arrangement, peak generation capacity costs could be based on the collective coincident demand of all of EVgo's DCFC on a utility's system during peak hours.

There are other ways that EVgo could potentially reduce its costs, using technology solutions like on-site solar or electricity storage systems that could be called upon to deliver power when grid power costs are high, or when the charger is at risk of triggering demand charges. However, our analysis was restricted to tariff-based solutions.

SUGGESTIONS FOR FURTHER STUDY

Although the current usage patterns of charging infrastructure suggest that it is easier for Level 2 chargers than it is for DCFC to shift their loads in response to TOU tariffs and provide grid benefits (such as demand response and ancillary services), more sophisticated and detailed modeling of DCFC's demand flexibility may offer some useful insights, particularly if DCFC are paired with on-site solar systems, an Option R tariff and/or on-site supplementary battery storage systems that can be deployed to shave demand peaks.

That kind of modeling work does not appear to have been done to a deep level as yet; most of the existing work has looked at the potential value streams of EVs as grid assets from the perspective of the bulk power system or in terms of the total societal impact, rather than at a granular level where effects on the distribution system over time could be assessed. It may very well be, for example, that the cost of a PV canopy and a redundant battery storage array located with a DCFC looks prohibitive at first blush, but a detailed modeling of the revenue potential in such a configuration would show that it would not only substantially reduce the direct costs of the DCFC by shaving or avoiding peak pricing and demand charges, but earn significant revenue for selling grid services to utilities, and enabling the uptake of renewable power on the grid to a degree that public utility commissioners see the value in developing performance-based incentives around it.

ENDNOTES

[1] United States GDP Growth Rate, Trading Economics. http://www.tradingeconomics.com/united-states/gdp-growth

[2] RMI, Peak Car Ownership. 2016. https://rmi.org/Content/Files/CWRRMI_POVdefection_FullReport_L12.pdf

[3] Data on the number of gasoline filling stations in California is hard to find, but this source suggests 13,500, which seems in the right ballpark. If we assume 6 pumps per station, then there would be 81,000 pumps in California, compared to the 63,500 DCFC in California in 2027 under Scenario 4. http://www.answers.com/Q/How_many_gas_stations_in_California?#slide=2

[4] Documents pertaining to CPUC proceeding R.13-11-007 may be found here: https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO

[5] San Diego Gas & Electric, "Application of San Diego Gas & Electric Company (U 902-E) for Authority to Implement Priority Review and Standard Review Proposals to Accelerate Widespread Transportation Electrification," January 20, 2017. https://www.sdge.com/regulatory-filing/20491/application-sdge-authority-implement-priority-review-and-standard-review

[6] "Prepared Direct Testimony of Cynthia Fang on Behalf of San Diego Gas & Electric Company, Chapter 5," January 20, 2017. https://www.sdge.com/sites/default/files/regulatory/Direct%20Testimony%20Chapter%205%20-%20Rate%20Design.pdf

[7] "Prepared Testimony of Randy Schimka on Behalf of San Diego Gas & Electric Company, Chapter 3," January 20, 2017. https://www.sdge.com/sites/default/files/regulatory/Direct%20Testimony%20Chapter%203%20-%20Priority%20Review%20Projects.pdf

[8] Ibid.

[9]

> A CPP [Critical Peak Pricing] rate is a commodity rate structure that includes a higher energy price ($/kWh) applied to peak periods on critical system event days that are called on a day-ahead basis. The CPP rate is designed to recover the costs of system capacity during event days, up to 18 days per year with an assumed nine days per year, called on a day-ahead basis rate rather than through a peak demand charge every month of the year in order to solicit demand response....Customers will be notified on a day-ahead basis when forecasted load exceeds an established threshold with the threshold

calculated based on the top 150 system hours from the previous year, which represents approximately 1.71% of annual hours. By moving from a ToU rate structure to an hourly dynamic rate structure, the proposed TE commodity rate allows SDG&E to focus on a small number of truly high cost hours, the 150 system peak hours, while still reflecting the cost basis of commodity services.

"Prepared Direct Testimony of Cynthia Fang on Behalf of San Diego Gas & Electric Company, Chapter 5," January 20, 2017. https://www.sdge.com/sites/default/files/regulatory/Direct%20Testimony%20Chapter%205%20-%20Rate%20Design.pdf

10 Historic circuit load will be used to determine the threshold amount for forecasting the top 200 circuit peak hours. When the forecast identifies an hour exceeding the prior year's top 200-hour threshold, a D-CPP Hourly Adder will be applied and presented to the customer on a day-ahead basis. Year-to-year differences in load can result in actual circuit peak hours that differ from the forecasted top 200 hours.

Ibid.

11 Ibid.

12 "Prepared Direct Testimony of Cynthia Fang on Behalf of San Diego Gas & Electric Company, Chapter 5," January 20, 2017. https://www.sdge.com/sites/default/files/regulatory/Direct%20Testimony%20Chapter%205%20-%20Rate%20Design.pdf

13 Assuming a 32 mpg Nissan Sentra ICE vehicle, $3/gallon of gasoline (based on CA price in Q4 2016) 0.32 kWh/mile typical EV performance, and $12/MWh CAISO day-ahead pricing in central San Diego (as of February 14, 2017). http://gasprices.aaa.com/?state=CA; https://www.fueleconomy.gov/feg/bymodel/2015_Nissan_Sentra.shtml;

http://www.afdc.energy.gov/vehicles/electric_emissions_sources.html.

14 Southern California Edison, "Testimony of Southern California Edison Company in Support of its Application of Southern California Edison Company (U 338-E) For Approval of its 2017 Transportation Electrification Proposals," January 20, 2017. http://on.sce.com/2kXeu1X

15 Lazar, J. and Gonzalez, W. (2015). *Smart Rate Design for a Smart Future*. Montpelier, VT: Regulatory Assistance Project. http://www.raponline.org/document/download/id/7680

16 "While the costs of utility services are incurred in the same manner for all customer classes, there is little consistency in how costs are recovered from each customer class, with the rate structure for some customer classes recovering costs in a manner that does not reflect cost causation." "Prepared Direct Testimony of

Cynthia Fang on Behalf of San Diego Gas & Electric Company, Chapter 5," January 20, 2017. https://www.sdge.com/sites/default/files/regulatory/Direct%20Testimony%20Chapter%205%20-%20Rate%20Design.pdf

[17] CPUC Decision 14-12-080, "Decision on a Rate Design Proposal to Adopt an Option R Tariff for Pacific Gas and Electric Company," December 18, 2014. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K631/143631744.PDF

[18] Lazar, J. and Gonzalez, W. (2015). *Smart Rate Design for a Smart Future*. Montpelier, VT: Regulatory Assistance Project. http://www.raponline.org/document/download/id/7680

[19] Chris Nelder, James Newcomb, and Garrett Fitzgerald, Electric Vehicles as Distributed Energy Resources (Rocky Mountain Institute, 2016), http://www.rmi.org/pdf_evs_as_DERs

[20] SDG&E Time of Use Plus (Critical Peak Pricing- CPP-D) option. http://www.sdge.com/business/demand-response/cpp

Exhibit JRB-6

I/A

ROCKY MOUNTAIN INSTITUTE

1820 Folsom Street
Boulder, CO 80302 USA
http://www.rmi.org

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1214

In the Matter of:	)
Application of Duke Energy Carolinas,	)
LLC for Adjustment of Rates and	)
Charges Applicable to Electric Service	)
in North Carolina	)

DIRECT TESTIMONY OF
JUSTIN R. BARNES
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT JRB-7

I/A

minnesota power
AN ALLETE COMPANY

Jenna Warmuth
Senior Public Policy Advisor
218-355-3448
jwarmuth@mnpower.com

May 16, 2019

VIA ELECTRONIC FILING
Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

RE: In the Matter of Minnesota Power's Docket No. Petition for Approval of its Electric Vehicle Commercial Charging Rate Pilot Docket No. E015/M-19-___

Dear Mr. Wolf:

Minnesota Power herby submits this Petition to the Minnesota Public Utilities Commission ("Commission") in accordance with Commission Order in Docket No. E999/CI-17-879 and pursuant to Minnesota Rules 7829.00, subp. 1, and 7826.1300. Minnesota Power is proposing a three year Electric Vehicle Commercial Charging Rate Pilot for Commercial and Industrial Customers (the "Pilot Program"). The Pilot proposal consists of on-and-off peak periods as well as a 30 percent cap on demand charges and is designed to address the high demand charges associated with EV charging, particularly in fleet and public charging applications.

This Pilot is an important first step in incentivizing EV adoption and meeting the needs of early adopting customers. Minnesota Power is submitting this Pilot Program proposal to the Commission in order to take advantage of current and upcoming EV opportunities within its service territory while meeting customer expectations.

Objectives for the Pilot:
Ease of Use: The Company designed the Pilot so that it is easy for customers to implement and utilize.

Education and Learning: The Pilot should allow customers to get comfortable with the EV charging technology and provide information to Minnesota Power about the costs to serve these customers. Many of these customers have never worked with EV charging infrastructure and will require time to adapt and experiment for optimal usage.

The Company appreciates the Commission's attention to this matter and is available to answer any questions related to the proposed Pilot Program.

Please contact me at the number above with any questions related to this matter.

Respectfully,

Jenna Warmuth

STATE OF MINNESOTA

BEFORE THE

MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's Petition for Approval of its Electric Vehicle Commercial Charging Rate Pilot	Docket No. E015/M-19-___ **PETITION**

Summary of Filing

Minnesota Power (or "the Company") submits this Petition to the Minnesota Public Utilities Commission ("Commission") in accordance with Commission Order in Docket No. E999/CI-17-879 and pursuant to Minnesota Rules 7829.00, subp. 1, and 7826.1300. Minnesota Power respectfully requests that the Commission approve its Electric Vehicle Commercial Charging Rate Pilot as proposed.

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STATE OF MINNESOTA

BEFORE THE

MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's Petition for Approval of its Electric Vehicle Commercial Charging Rate Pilot

Docket No. E015/M-19-___

PETITION

I. INTRODUCTION

In its February 1, 2019 Order Making Findings and Requiring Filings, the Minnesota Public Utilities Commission established general findings, specific findings, and outlined directives for Minnesota's utilities related to the advancement and adoption of electric vehicle ("EV") integration.

General Findings:

- ❖ Electrification is in the public interest
- ❖ Barriers to increased EV adoption in Minnesota include but are not limited to: (a) inadequate supply of and access to charging infrastructure, and (b) lack of consumer awareness of EV benefits and charging options.
- ❖ How EVs are integrated with the electric system will be critical to ensuring that transportation electrification advances the public interest.
- ❖ Minnesota's electric utilities have an important role in facilitating the electrification of Minnesota's transportation sector and optimizing the cost-effective integration of EVs.

Specific Findings:

- ❖ Minnesota's investor owned utilities should take steps to encourage the cost-effective adoption and integration of EVs
- ❖ The following should be included at a minimum in any EV-related utility proposals:
  - o Any EV-related proposals that involve significant investments for which the utility is seeking or will seek cost recovery should include a cost-benefit analysis that shows the expected costs along with the expected ratepayer, system and societal benefits associated with the proposal
  - o In the case of a proposed pilot, the utility filing should include specific evaluation metrics for the pilot and identify what the utility expects to learn from the pilot.
- ❖ Utilities should use the Commission's current environmental externality values for carbon and criteria pollutants in analyzing the societal costs and benefits associated with EV-related proposals. Cost-benefit analyses should consider potential long-term ratepayer and societal benefits, including better grid management, public health, and other social

benefits. These analyses should also consider potential long-term costs, including the risk of stranded investment.

- The Office of the Attorney General ("OAG") suggested three-step process for evaluating utility investments in public charging infrastructure is reasonable.
- Utility investments and arrangements related to charging infrastructure should be designed to ensure interoperability, using standard such as Open Charge Point Protocol and Open Automated Demand Response.
- No single method of cost recovery should be generally precluded at this time for any EV-related investments.
- Minn. Stat. § 216B.1614, subd. 2(c)(2), allows utilities the opportunity to recover costs related to educating customers on the benefits of EVs beyond those costs related specifically to the utility's EV tariffs.

Actions:

Table 1: Commission Action - Electric Vehicles

Filing	Due Date
Report of planned 2019 EV proposals	March 31, 2019
Annual EV Reports required under Minn. Stat. § 216B.1614, subd. 3, including promotional cost recovery mechanisms	June 1, 2019
Transportation Electrification Plan	June 30, 2019
Proposals for infrastructure, education, managed charging, etc.	No later than October 31, 2019

- In any future pilot proposal, utilities should include a discussion of the following topics to the extent relevant:
    - Environmental justice, with a focus on communities disproportionately disadvantaged by traditional fossil fuel use;
    - Low-income access and equitable access to vehicles and charging infrastructure, which can include all-electric public transit and EV ride-sharing options;
    - Environmental benefits, including but not limited to carbon and other emission reductions;
    - Potential economic development and employment benefits in Minnesota;
    - Interoperability and open charging standards;
    - Load management capabilities, including the use of demand response in charging equipment or vehicles;
    - Energy and capacity requirements;
    - Pilot expansion and/or transition to permanent status at a greater scale;

- o Education and outreach;
- o Market competitiveness/ownership structures;
- o Distribution system impacts;
- o Cost and benefits of the proposal;
- o Customer data privacy and security; and
- o Evaluation metrics and reporting schedule.

Minnesota Power submits this Petition in accordance with the above referenced Commission findings and actions.

SUMMARY OF PILOT PROPOSAL:

Minnesota Power is proposing a three year Electric Vehicle Commercial Charging Rate Pilot for Commercial and Industrial Customers (the "Pilot Program"). The Pilot proposal consists of on-and-off peak periods as well as a 30 percent cap on demand charges and is designed to address the high demand charges associated with EV charging, particularly in fleet and public charging applications, as depicted in Table 2. This Pilot proposal is an initial step towards incentivizing EV charging and will need to be refined as current barriers, as outlined in Section II, are overcome and knowledge is gained. Full details of the Pilot proposal rate structure can be found in Section III of this Petition.

Table 2: Tariff Design

	CURRENT GENERAL SERVICE DEMAND TARIFF	PROPOSED PILOT PROGRAM TARIFF
ON-PEAK DEMAND CHARGE[1]	$6.50	$6.50
OFF-PEAK DEMAND CHARGE	$6.50	$0.00
ENERGY CHARGE	$0.07619	$0.07619
OTHER		30% DEMAND CAP

PURPOSE AND OBJECTIVES OF THE PILOT PROPOSAL:

Minnesota Power is submitting this Pilot proposal to the Commission in order to take advantage of current and upcoming EV opportunities within its service territory while meeting customer

[1] Minnesota Power's standard General Service rate does not include on-and-off-peak periods.

expectations. The Company is placing an emphasis on encouraging a growing market by reducing costs to public and fleet EV charging customers.

Objectives for the Pilot:

Ease of Use: The Company designed the Pilot so that it is easy for customers to implement and utilize.

Education and Learning: The Pilot should allow customers to get comfortable with the EV charging technology and provide information to Minnesota Power about the costs to serve these customers. Many of these customers have never worked with EV charging infrastructure and will require time to adapt and experiment for optimal usage.

Minnesota Power respectfully requests that the Commission approve its Electric Vehicle Commercial Charging Rate Pilot as proposed.

II. PROCEDURAL MATTERS

In accordance with Minn. Rule Minn. Stat. § 216B.1614, as well as the administrative rules governing this request, Minn. R. 7829.1300, Minnesota Power submits its Electric Vehicle Commercial Charging Tariff Pilot proposal.

Minnesota Power submits the following information:

A. Name, Address, and Telephone Number of Utility
(Minn. Rules 7825.3500 (A) and 7829, subp. 3 (A))
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 722-2641

B. Name, Address, and Telephone Number of Utility Attorney
(Minn. Rules 7825.3500 (A) & 7829, subp. 3 (B))
David R. Moeller, Senior Attorney
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 723-3963
dmoeller@allete.com (e-mail)

C. Date of Filing and Date Proposed Rates Take Effect
This petition is being filed on May 15, 2019. The proposed rate will take effect upon Commission approval.

D. Statute Controlling Schedule for Processing the Petition
This petition is made in accordance with Commission Order in Docket No. E999/CI-17-879 and pursuant to Minnesota Rules 7829.00, subp. 1, and 7826.1300.

Minnesota Power's request for its Electric Vehicle Commercial Charging Tariff Pilot, falls within the definition of a "Miscellaneous Tariff Filing" under Minn. Rules 7829.0100, subp. 11 and 7829.1400, subp. 1 and 4 permitting comments in response to a miscellaneous filing to be filed within 30 days, and reply comments to be filed no later than 10 days thereafter.

E. Utility Employee Responsible for Filing
Jenna Warmuth
Senior Public Policy Advisor
30 West Superior Street Duluth, MN 55802
(218) 355-3448
jwarmuth@mnpower.com (e-mail)

F. Official Service List

Pursuant to Minn. Rule 7829.0700, Minnesota Power respectfully requests the following persons to be included on the Commission's official service list for this proceeding:

David R. Moeller	Jenna Warmuth
Senior Attorney	Senior Public Policy Advisor
Minnesota Power	Minnesota Power
30 West Superior	30 West Superior Street
Duluth, MN 55802	Duluth, MN 55802
(218) 723-3963	(218) 355-3448
dmoeller@allete.com	jwarmuth@mnpower.com

G. Service on Other Parties

Minnesota Power is eFiling this report and notifying all persons on Minnesota Power's General Service List, Service Lists for Docket Nos E999/CI-17-879 and E015/M-15-120 that this report has been filed through eDockets. A copy of the service list is included with the filing along with a certificate of service.

H. Filing Summary

As required by Minn. Rule 7829.1300, subp. 1, Minnesota Power is including a summary of this filing on a separate page.

SUMMARY OF FILING REQUESTS

Based on information provided throughout this filing, Minnesota Power requests the following:

From the MPUC:

- Acceptance of its proposed Electric Vehicle Commercial Charging Tariff Pilot.

III. BACKGROUND

In its June 1, 2018 annual compliance filing in Docket No. E015/M-15-120, Minnesota Power communicated its intent to submit a commercial EV tariff designed to address high demand charges typically associated with commercial EV charging and shift EV charging to off-peak time periods. As described in the June 1, 2018 filing, one driver for the focus on commercial EV charging rates is the Duluth Transit Authority's ("DTA") procurement of seven fully electric Proterra[2] transit buses in the third quarter of 2018. The Company has worked with the DTA to understand the customer experience and challenges of operating electric buses in a northern climate. In addition to the DTA, Minnesota Power has engaged in conversations with customers interested in converting their fleets to electric vehicles, potential site hosts for public charging stations, and public charging companies that have deployed (or plan to deploy) EV charging within Minnesota Power's service territory to better understand their challenges as they relate to Minnesota Power rates. The insights gained from these conversations and interactions were used in the development of this Pilot.

In its February 1, 2019 Order Making Findings and Requiring Filings in Docket No. E015/M-17-879, the Commission directed the investor-owned utilities in Minnesota to file proposals, which can be pilots, to enhance the availability of or access to charging infrastructure, increase consumer awareness of EV benefits, and/or facilitate managed charging or other mechanisms that optimize the incorporation of EVs into the electric system. Minnesota Power recognizes that EV-enabling rates are a critical component of advancing the electric vehicle market in Minnesota. This Pilot proposal is intended to provide a short-term solution to barriers commonly experienced in commercial charging applications while also recognizing that more information is needed before Minnesota Power can formulate a permanent rate for these applications.

Utilities around the country are working to understand how to best serve this emerging class of customers through rates, infrastructure, programs and more. A report released in January 2019 by The Brattle Group describes the options for increasing adoption of direct current fast charging stations ("DCFC") through rates.[3] According to the report, "designing the "perfect" DCFC rate may not need to be the top priority initially. Experimentation and learning what works to facilitate DCFC adoption in an equitable and efficient manner may be more appropriate near-term objectives." Placing limits on demand-related charges, as this Pilot proposes to do, is one option described in the report as a means to facilitate DCFC deployment.

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[2] See https://www.proterra.com/ for more information.

[3] See http://files.brattle.com/files/15077_increasing_ev_fast_charging_deployment_-_final.pdf

STAKEHOLDER OUTREACH

Minnesota Power intentionally engaged multiple stakeholders in the development of this Pilot. These stakeholder included the Duluth Transit Authority, Fresh Energy, Office of the Attorney General, Department of Commerce, ChargePoint, Citizens Utility Board, Greenlots, Tesla and ZEF Energy. While not all of the stakeholder's concerns or needs could be addressed in this initial Pilot design, the discussions have proven valuable and the Company is better prepared to address each stakeholder's concerns. The Pilot analysis will also be designed in a way that will provide insight into these areas of concern and interest.

Consultation with customers and the above-mentioned stakeholders informed the development of this Pilot proposal which is designed to address the high demand charges associated with EV charging, particularly in fleet and public charging applications. Utilities around the country are working to better understand the characteristics of EV charging customers in an attempt to develop best practices to encourage optimized charging. The enclosed Pilot proposal was designed as a short-term solution to meet the immediate needs of commercial customers who have installed, or are considering installing, EV charging infrastructure for public and fleet applications. A bridging solution is needed to remove barriers to entry into the market while the Company continues to gather and analyze data needed to design a rate that provides more accurate price signals for optimized charging. This Pilot is an educational tool for customers to begin experimenting with load shifting. It is meant to encourage thoughtful and beneficial charging that will not only reduce costs for EV customers, but also support enhanced grid management.

TECHNOLOGY AND METERING CONSIDERATIONS

Currently, over 50 percent of Minnesota Power's meters in the field are advanced metering infrastructure ("AMI"). Minnesota Power is actively deploying AMI throughout its service territory, largely through meter attrition, at a rate of approximately 6-8 percent (roughly 10,000 meters) annually, continuing over the next several years. Minnesota Power estimates full deployment of all AMI meters by the end of 2025. Along with the AMI meter deployment, Minnesota Power completed implementation of its Radio Frequency AMI network communications infrastructure in 2018.

Upon implementation of its new Meter Data Management ("MDM") system, the Company will have the capability to bill customers utilizing hourly data received from the meters. Usage bucketing will be handled by the MDM, thereby removing the need for manual custom programming of meters for more complex time-varying rates. Consequently, scalability and speed to enroll customers in an innovative or time-varying rate will increase significantly and the associated cost will decrease significantly. With a MDM in place, it is easier for the meters to communicate usage rather than the current practice of getting them to recognize and accept a command. This will result in fewer billing issues and far less manual billing interventions. In the current context, the meters bucket all usage and communicate a large daily file back to the Company's Customer Information System ("CIS"). With a full AMI/MDM established, the data will be transmitted several times a day, which typically equals greater success. A MDM will also allow for flexibility to efficiently change the time periods for rates.

The Company completed a request for proposal (“RFP”) process and MDM selection in late 2018. As a result of its robust RFP process, the Company selected the Oracle Customer to Meter Solution (“Oracle C2M”) in November of 2018. The next step in the MDM implementation process is to select a System Integrator (“SI”) to assist with the design, build, testing, and implementation of the Oracle C2M solution. The Company currently has an RFP process underway and anticipates SI selection in 3rd quarter of 2019. The presence of a MDM will create a more user-friendly experience for customers and also has the potential to drastically reduce manual billing and programming issues currently experienced with customized rates and programs.

With the complete deployment of AMI and the implementation of the MDM Minnesota Power will have the capability to efficiently revise peak time periods as well as gain enhanced insight into customer usage patterns. In all practicality, an MDM solution needs to be in place systemically prior to system-wide rollout of several time varying rate programs. The Company is currently awaiting Commission direction on its February 20, 2019 filing in Docket No. E015/M-12-233 which outlines how a system-wide Time-of-Day rate could be implemented in Minnesota Power’s service territory. The outcome of this docket will likely inform many program offerings, including this Pilot proposal.

IV. TARIFF DESIGN

TARIFF DESIGN OVERVIEW:

Minnesota Power is proposing an Electric Vehicle Commercial Charging Rate Pilot for Commercial and Industrial customer's electric service requirements for electric vehicle loads including battery charging and accessory usage which are supplied through a separate meter. The Pilot proposal will have a limited three-year term. Service will be limited to customers with total power requirements greater than 10 kW but less than 10,000 kW and will be subject to Company's Electric Service Regulations and any applicable Riders. With the continued expansion of transportation electrification, the Company is interested in gathering data on how best to serve these customers and the costs to serve this customer class, while at the same time providing incentives to efficiently and cost-effectively utilize grid resources.

The Company examined the usage patterns of six commercial customers who currently have electric vehicle charging infrastructure in use. All of these customers are currently billed under the General Service Demand ("GSD") rate. As shown in Table 3 the current demand charge total represents more than 50 percent of these customers' bills, and in some cases more than 80 percent. Dividing an average GSD customer's total bill by their monthly usage results in a cost of roughly $0.08 per kWh, whereas these commercial EV charging customers are typically paying more than four times that amount.

The Company compared these six customers to all GSD customers and found that they are in the upper 90th percentile when customer bills are expressed as a dollars per kWh metric ("$/kWh"). This is directly related to these customers having relatively low load factors, which ranged from approximately 1% – 8%. Knowing that customers with low load factors also tend to have low coincidence factors, it stands to reason that these type of customers are less likely to experience peak demands coincident with the Company's system peak. To address the fact that these customers are paying significantly more per kWh than nearly all other GSD customers, the Company is proposing to implement a cap on demand charges. The proposed demand charge for this pilot will not make up more than 30 percent of a customer's monthly bill, and in addition, demand charges during off-peak time periods will be eliminated altogether to promote customer charging at times that are more advantageous to the distribution grid.

The purpose of the proposed 30 percent demand cap is to bring these customers more in-line with other GSD customers on a $/kWh basis. As shown in Table 4 doing so moves these customers closer to the average $/kWh percentile rank with an average total rate of roughly $0.12 per kWh.

Table 3: Current Demand Charge Impact

Customer	Demand Charge as % of Bill	Bill/kWh	Percentile Rank (Bill/Kwh) among GSD
1	56%	$ 0.19	94.8%
2	75%	$ 0.34	98.8%
3	73%	$ 0.31	98.7%
4	78%	$ 0.38	99.1%
5	78%	$ 0.39	99.1%
6	88%	$ 0.78	99.7%

Table 4: Demand Charge Impact of Pilot Tariff

Customer	Demand Charge as % of Bill	Bill/kWh	Percentile Rank (Bill/Kwh) among GSD
1	30%	$ 0.12	65.5%
2	30%	$ 0.12	67.0%
3	30%	$ 0.12	67.7%
4	30%	$ 0.12	69.7%
5	30%	$ 0.12	69.8%
6	30%	$ 0.14	82.7%

Demand charges serve a specific purpose for incentivizing flattening of individual customer peak loads. However, as outlined in the Regulatory Assistance Project's ("RAP") June 2018 "Ensuring Electrification in the Public Interest" report, "*the intent of beneficial electrification should be to provide incentives for customers to adjust their usage in a way that is helpful for managing system peaks.*"[4] The report goes on to state, "*more effective rate structure[s] would encourage these customers to move their charging to off-peak times for the grid as a whole, when it is less stressed*

[4] Farnsworth, Shipley, Lazar, Seidman "Ensuring Electrification in the Public Interest" https://www.raponline.org/knowledge-center/beneficial-electrification-ensuring-electrification-public-interest/

and less expensive to serve (Farnsworth, et al. 43)." The peak periods also proposed through this Pilot are an appropriate and advantageous starting point to meet these beneficial electrification objectives. By reducing the impact of demand charges for these customers, it provides flexibility for them to charge at times that are more advantageous to the distribution grid.

Demand Charge for On-Peak

For the purposes of this Pilot proposal the Billing Demand is defined as the kW measured during the 15-minute period of the customer's greatest use during the specified On-Peak periods during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract. On-Peak periods are defined as 8:00 a.m. to 10:00 p.m., Monday through Friday, inclusive, excluding holidays. Holidays are those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas. All other hours are considered to be Off-Peak periods and there is no demand charge applied during these times. Minnesota Power recognizes that targeted On-Peak time periods would be ideal for this rate and for these customers. However, there are currently limitations to the AMI and MDM data/billing process as discussed earlier in this filing, as well as limited information on the usage patterns for these customers. Attempting to create a more targeted peak period for these commercial load customers is unadvisable without first providing an opportunity for both customer and utility education and analysis.

While the current/proposed On-Peak period covers a broad portion of the day, it does generally align with the Company's system load profile as depicted in Figure 1. Minnesota Power has a high load factor due to the predominance of large industrial customers in its customer mix. This translates to a unique load profile when compared to other utilities across the United States. Minnesota Power's system is winter-peaking, with highest demand typically occurring on a winter evening, either in December or in January. It is also notable that the summer system peak typically occurs earlier in the day, in the afternoon, compared to the evening winter peak. The proposed On-Peak period for the Pilot follows these high demand time periods and will not only aid the Company in more effectively managing its grid resources, but will also take advantage of periods of high renewable penetration, mainly wind, during the overnight hours.

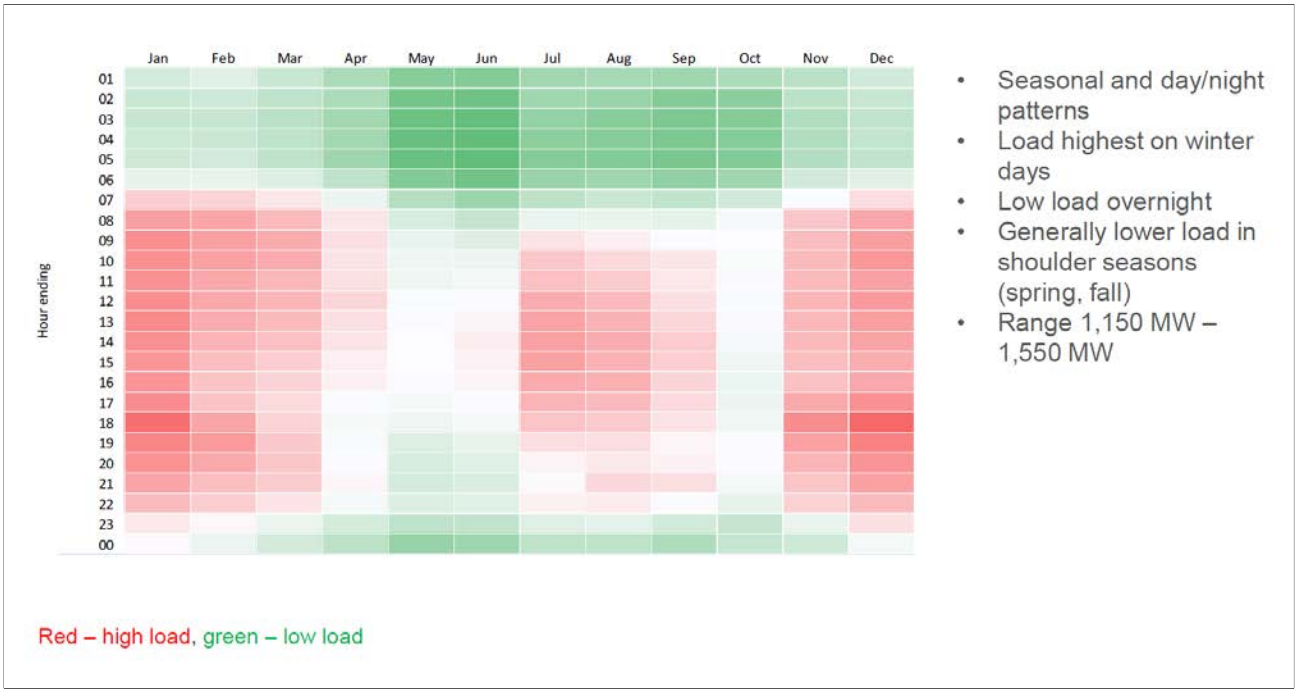

Figure 1: Gross Load Heat Map

Energy Charge for all kWh

The energy charge for the Pilot proposal will be set equal to the standard GSD rate energy charge. At this time Minnesota Power's GSD energy charge is equal to 7.619¢. This rate will be multiplied by all kWh used during the billing period.

Barriers Addressed through Tariff Design

At a high-level the Company is attempting to address the most prominent barriers to fleet and public EV charging applications with this Pilot. The Company realizes this is not a definitive solution and is excited to partner with customers that are going through early iterations of business model and technology pilots in the electrification of transportation movement. For fleet, the long-term strategy will be to send price signals that incentivize customers to charge when it's most beneficial for the grid– times of high overall available capacity. At face-value it may seem that fleet owners will be able to be precise and intentional with their charging patterns, but as medium and heavy duty fleet technology is still in the very early stages (especially within Northern Minnesota and cold climates) there needs to be room for flexibility. Transit, short-haul delivery, and school buses may not be able to limit their charging to the off-peak hours and still meet the current needs of business-as-usual, i.e. no impacts to their current routes.

As mentioned, the Company has engaged the DTA in ongoing discussions to support its innovative program. Minnesota Power is interested in providing alternative rate design options for low-load-factor customers similar to the DTA and public charging that wish to deploy DCFC. Load factor characteristics often associated with facilities deploying DCFC stations can lead to high demand charges for charging stations relative to their low utilization of energy, thereby reducing the cost effectiveness of electric transit options. Recognizing the significantly different load profile of DCFC facilities as compared to average commercial customers, the Company developed its Pilot proposal to mitigate these high demand charges. This program will also educate customers on the benefits of off-peak charging and provide incentives to shift demand to off-peak times.

For both fleet and public vehicle charging, demand charges are a barrier, but most significantly to a public charging station, which typically has a low load-factor. By capping demand rate billings, the Company is minimizing the economic risks to these public charging station owners, which are so critical to the advancement of electric transportation adoption. The 30 percent cap was determined to be a balanced approach that recognizes most public charging takes place during the On-Peak period, but lowers the impact that demand would have to a level that doesn't discourage progress. All while the industry transitions to rates that support beneficial electrification and grid modernization.

V. COMPLIANCE

Low-income access and equitable access to vehicles and charging infrastructure, which can include all-electric public transit and EV ride-sharing options;

"*According to a 2017 report from the Center for Climate and Energy Solutions*[5]*, emissions-related health issues like higher risk of cancer, asthma, emphysema, heart disease and inhibited child development disproportionately impact lower income communities. … EVs can combat these issues, according to the report, benefiting these communities three-fold through improved air quality, reduced greenhouse gas emissions and savings in terms of operating costs like fuel and maintenance expenses.*[6]*"* As outlined in the Center for Climate and Energy Solutions report, the expansion of any fleet, transit, or public charging expansion will positively affect low income customers because EVs produce no tailpipe emissions. The Company recognizes the need for tailored low income EV programming and plans to examine possible program structures for future development.

The intent of this Pilot proposal is to encourage deployment of commercial EV charging applications including work place, public and fleet such as electric buses. While this Pilot is not specifically designed to increase low income or equitable access to EV charging, increasing the amount of EV chargers available for public use will benefit all Minnesota Power customers.

Environmental benefits, including but not limited to carbon and other emission reductions;

In 2017, transportation was the leading sector for GHG emissions in United States[7]. As the electricity sector continues to reduce emissions this will only improve the environmental benefits of electrifying the transportation sector.

Electric Vehicles eliminate (Battery Electric Vehicles (BEV)) or dramatically reduce (Plug-in Hybrid Electric Vehicles) tailpipe emissions (nitrogen oxides (NOx), and fine particles ($PM_{2.5}$)) from individual vehicles, as well as reduce the overall "well-to-wheel" greenhouse gas emissions (GHG) associated with electrifying the transportation sector[8]. A BEV charged from Minnesota's grid vs. a gasoline vehicle already emits less overall carbon dioxide equivalent (CO_2e), NO_x, and $PM_{2.5}$ according to the Minnesota Pollution Control Agency, as shown below. Electricity is continually sourced from cleaner and more renewable sources, only improving the projections of environmental benefits

[5] https://www.c2es.org/site/assets/uploads/2017/11/electrified-transportation-for-all-11-17-1.pdf

[6] https://sustainableamerica.org/blog/making-evs-possible-for-low-income-drivers/

[7] https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions

[8] https://www.pca.state.mn.us/air/electric-vehicles

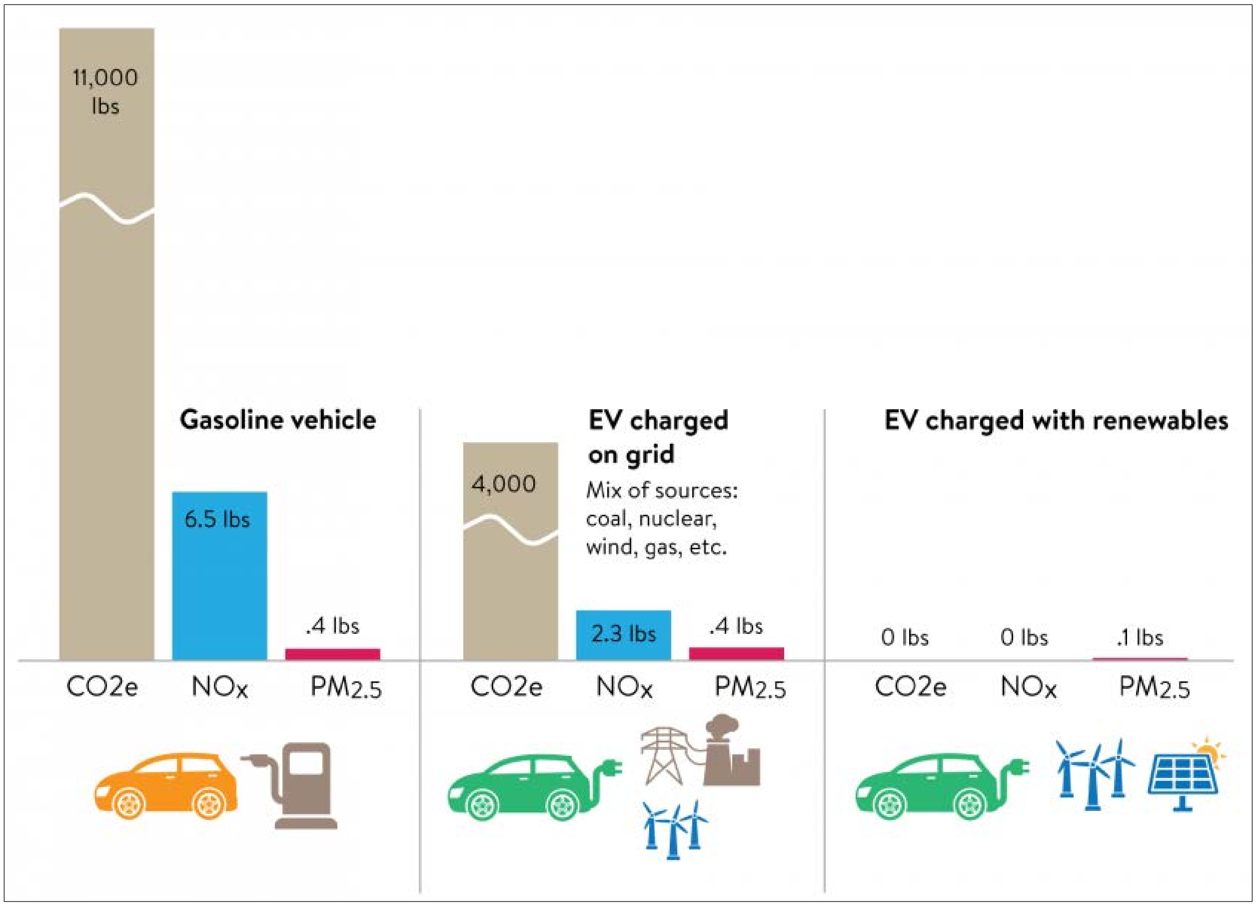

Figure 2: Annual emissions from electric vehicles and gasoline vehicles in Minnesota (12,000 miles)

Furthermore, optimizing when these vehicles charge through price signals to the customer, or future technology-based smart charging could aid in minimizing the impacts of adding to system peaks or need for additional capacity. Electric vehicles are more energy efficient and at the center of the beneficial electrification movement. According to the U.S. Department of Energy, EVs convert about 59 to 62 percent of the electrical energy from the grid to power at the wheels. Their internal combustion engine counterparts only convert 17 to 21 percent of the energy stored in gasoline to power at the wheels[9]. These efficiency numbers do not include energy used in the production of the electricity or gasoline.

In addition to Light Duty Vehicles, Minnesota Power considers public transit greatly important when prioritizing initiatives to support the growth of various applications of electric transportation. “By moving more people with fewer vehicles, public transportation can reduce greenhouse gas emissions. National averages demonstrate that public transportation produces significantly lower

[9] https://www.fueleconomy.gov/feg/evtech.shtml

greenhouse gas emissions per passenger mile than private vehicles[10]". Electrifying public transit, which is already more efficient in principle than light-duty vehicles, will only improve the reductions in GHG and optimization of the grid. A Battery Electric Bus ("BEB") represents a significantly higher amount of demand and energy usage.

According to a 2018 study conducted by the National Renewable Energy Laboratory ("NREL") in California, BEBs demonstrated more than twice the efficiency on a miles per gallon equivalent, compared to a diesel bus.[11] The Duluth Transit Authority is currently participating in a similar pilot. While these results are promising, Minnesota Power and the DTA have been in communications about the various other benefits and drawbacks unique to our region and climate.

Energy and capacity requirements;

The Company expects minimal short-term change in energy and capacity requirements due to the initiation of this Pilot. However, the longer-term impacts of this Pilot or any subsequent Commercial EV rate could be substantive.

Energy and capacity requirements will grow with EV adoption. The proposed Pilot is not intended to reduce energy use, only to shift that energy use to off-peak periods. Overall energy requirements are unlikely to be affected by this Pilot in the short-term. However, in the long-term, it's likely that the incentive offered in this Pilot will accelerate adoption of EV's and increase overall energy requirements on the system. Any on-peak to off-peak load shifting will reduce the Company's system demand relative to a "no load-shifting" scenario.

Education and outreach;

Minnesota Power has continually engaged current and potential EV owning commercial customers as outlined through this Petition. The Company will continue to reach out to known EV owning commercial customers as well as make efforts to perform outreach to other potential qualified commercial customers.

The Company will advertise the Pilot program to potential qualified customers through its website, promotional materials and one-to-one contacts. The Company works closely with its commercial customers and plans to highlight the benefits of EV ownership as well as the optionality the Pilot proposal can provide their business and customers.

[10] https://www.transit.dot.gov/regulations-and-guidance/environmental-programs/transit-environmental-sustainability/transit-role

[11] https://afdc.energy.gov/files/u/publication/zero-emission_evaluation_county_connection_bec.pdf

Distribution system impacts;

The Company expects the Pilot program to have minimal impact on the distribution system in the short-term. Existing and future commercial EV customers are currently required to pay for installation of any distribution equipment upgrades necessary to serve new EV load. As such, these customers' EV loads do not currently present a burden for the distribution system. However, as EV charging becomes more prominent and demands on the distribution system increase, it will be beneficial to limit on-peak charging, particularly in fleet applications.

Cost and benefits of the proposal;

The cost of the Pilot proposal will relate to the addition of the installation of the required service, and can vary significantly based on customer location and energy use characteristics. All customers participating in the Pilot will require some additional meter programming to facilitate a difference in on/off-peak demand charges. This programming has a small incremental cost relative to a standard GSD meter, but these costs are not substantial enough at this time to justify additional monthly service charges.

The overall benefits of the proposal to Minnesota Power and customers will depend on how much energy use is shifted to off-peak time periods. Minnesota Power will quantify and analyze the costs and benefits of the Pilot through the various performance metrics outlined in this Petition.

Customer data privacy and security;

Minnesota Power will clarify in each participating customer's service agreement the data to be assigned trade secret and public designation. In keeping with Commission Order[12], the Company will only share a customer's data for a purpose other than related to regulated utility service after the utility obtains consent from the customer that includes a clear statement of the information to be shared and with whom it will be shared.

Evaluation metrics and reporting schedule;

Minnesota Power will track several metrics to assess the success of its proposed Commercial EV charging pilot. Several of these metrics are comparable to cost allocation factors used in Customer Cost of Service Studies and may indicate whether or not the Company was successful in reducing service costs. Other metrics focus on the customer's savings under this EV rate.

1. Daily/monthly coincidence factors - with Minnesota Power system peak and MISO system peak,
2. Daily/monthly on/off-peak and overall load factor
3. Average $/kWh and respective percentile rank within GS Demand
4. Comparison of final bills under different rate structures
5. Daily/monthly kW demand on and off- peak

[12] June 24, 2014 Order in Docket No. E,G-999-CI-12-1344

6. Pre-pilot usage for comparison.
7. Growth in the number of fleet EV or public charging stations.

Minnesota Power will leverage these metrics and stakeholder feedback to inform future rate and program development.

Pilot expansion and/or transition to permanent status at a greater scale;

Minnesota Power will offer the Pilot rate for a three-year period, thereby allowing the Company to:

- gather the information needed to design a rate that sends more accurate price signals and is based on the costs to serve EV charging customers,
- coordinate with the Company's other efforts including the MDM implementation, AMI deployment and time-of-day rate proceeding,
- encourage increased adoption of electric vehicles in northern Minnesota by decreasing the costs associated with public and fleet charging and allowing customers time to experiment with charging patterns and capabilities;
- and provide benefits to all Minnesota Power customers by encouraging charging in the off-peak where possible and increasing load, spreading system costs across a larger customer base.

The Company intends to evaluate the rate during the three-year pilot period based on the criteria listed in this petition and determine whether a commercial EV charging rate is needed going forward and if so, what changes are needed to better optimize EV charging in the future and as adoption increases.

VI. CONCLUSION

Minnesota Power submits this Petition in accordance with Commission findings and actions in Docket No. E999/CI-17-879. The Company appreciates the Commission's attention to this Pilot proposal. This Pilot is an important first step in incentivizing EV adoption and meeting the needs of early adopting customers. The Pilot is meant to be an easy to understand and foundational experience for current and potential fleet and public EV customers. The Pilot is designed to allow customers to adapt to the EV charging technology. It will also allow Minnesota Power to learn more about the costs to serve these customers. Minnesota Power respectfully requests that the Commission approve its Electric Vehicle Commercial Charging Rate Pilot as proposed.

Dated: May 16, 2019

Respectfully submitted,

J Warmuth

Jenna Warmuth
Senior Public Policy Advisor
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 355-3448
jwarmuth@mnpower.com

PILOT FOR COMMERCIAL ELECTRIC VEHICLE CHARGING SERVICE

RATE CODES

29EV

APPLICATION

Available while this Pilot Program is in effect, to Commercial and Industrial customer's electric service requirements for electric vehicle loads including battery charging and accessory usage which are supplied through one meter. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery. Service hereunder is limited to Customers with total power requirements greater than 10 kW but less than 10,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

Service Charge	$12.00
Demand Charge for On-Peak kW	$6.50
Energy Charge for all kWh	7.619¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The appropriate service charge plus any applicable Adjustments; however, in no event will the Minimum Charge (Monthly) for three phase service be less than $25.00 nor will the Demand Charge per kW of Billing Demand be less than the Minimum Demand specified in customer’s contract.

Plus any applicable Adjustments.

PILOT FOR COMMERCIAL ELECTRIC VEHICLE CHARGING SERVICE

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $2.00 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will be further subject to a discount 0.350¢ per kWh of Energy.

High Voltage Service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

2. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

3. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

4. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

5. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

6. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city’s Franchise Fee.

DETERMINATION OF THE BILLING DEMAND

The Billing Demand will be the kW measured during the 15-minute period of customer's greatest use during the On-Peak periods during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract. On-Peak periods shall be defined as 8:00 a.m. to 10:00 p.m., Monday through Friday, inclusive, excluding holidays. Holidays shall be those days nationally designated and celebrated as New Year’s Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas. All other hours are considered to be Off-Peak periods, and there is no Demand Charge applied during these times.

Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

DEMAND CHARGE CAP

In no month shall the Demand Charge exceed 30% of customer’s total bill excluding any applicable taxes and fees. If the Demand Charge is greater than 30% of the subtotal of the Service Charge, the Demand Charge, the Energy Charge, and all adjustments listed above, the customer shall receive an EV Demand Credit which will be applied against the Demand Charge, capping it at 30% of the pre-tax bill.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

STATE OF MINNESOTA	)	AFFIDAVIT OF SERVICE VIA
	) ss	ELECTRONIC FILING
COUNTY OF ST. LOUIS	)	

Jodi Nash, of the City of Duluth, County of St. Louis, State of Minnesota, says that on the 16th day of May, 2019 she served Minnesota Power's Petition for Approval of its Electric Vehicle Commercial Charging Rate Pilot on the Minnesota Public Utilities Commission and the Energy Resources Division of the Minnesota Department of Commerce via electronic filing. The persons on the attached Service List were served as requested.

Jodi Nash

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Aafedt	daafedt@winthrop.com	Winthrop & Weinstine, P.A.	Suite 3500, 225 South Sixth Street Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_17-879_Official
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_17-879_Official
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_17-879_Official
Thomas	Ashley	tom@greenlots.com	Greenlots	N/A	Electronic Service	No	OFF_SL_17-879_Official
Max	Baumhefner	MBAUMHEFNER@NRDC.ORG	Natural Resources Defense Council	111 Sutter St 21st Fl San Francisco, CA 94104	Electronic Service	No	OFF_SL_17-879_Official
Katie	Bell	ksheldon@tesla.com	Tesla	6801 Washington Ave S #110 Eden Prairie, MN 55439	Electronic Service	No	OFF_SL_17-879_Official
James J.	Bertrand	james.bertrand@stinson.com	Stinson Leonard Street LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official
William A.	Blazar	bblazar@mnchamber.com	Minnesota Chamber Of Commerce	Suite 1500 400 Robert Street North St. Paul, MN 55101	Electronic Service	No	OFF_SL_17-879_Official
Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.	12700 West Dodge Road PO Box 2047 Omaha, NE 68103-2047	Electronic Service	No	OFF_SL_17-879_Official
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_17-879_Official
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	No	OFF_SL_17-879_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Corey	Conover	corey.conover@minneapolismn.gov	Minneapolis City Attorney	350 S. Fifth Street City Hall, Room 210 Minneapolis, MN 554022453	Electronic Service	No	OFF_SL_17-879_Official
Heidi	Corcoran	Heidi.Corcoran@CO.DAKOTA.MN.US	Dakota County	N/A	Electronic Service	No	OFF_SL_17-879_Official
Carl	Cronin	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_17-879_Official
Frances	Crotty	Fran.Crotty@state.mn.us	MN Pollution Control Agency	520 Lafayette Rd St. Paul, MN 55155	Electronic Service	No	OFF_SL_17-879_Official
Leigh	Currie	lcurrie@mncenter.org	Minnesota Center for Environmental Advocacy	26 E. Exchange St., Suite 206 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_17-879_Official
James C.	Erickson	jericksonkbc@gmail.com	Kelly Bay Consulting	17 Quechee St Superior, WI 54880-4421	Electronic Service	No	OFF_SL_17-879_Official
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	1313 5th St SE #303 Minneapolis, MN 55414	Electronic Service	No	OFF_SL_17-879_Official
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_17-879_Official
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	OFF_SL_17-879_Official
Bruce	Gerhardson	bgerhardson@otpco.com	Otter Tail Power Company	PO Box 496 215 S Cascade St Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_17-879_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kimberly	Hellwig	kimberly.hellwig@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official
Shane	Henriksen	shane.henriksen@enbridge.com	Enbridge Energy Company, Inc.	1409 Hammond Ave FL 2 Superior, WI 54880	Electronic Service	No	OFF_SL_17-879_Official
Michael	Hoppe	il23@mtn.org	Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Electronic Service	No	OFF_SL_17-879_Official
Lori	Hoyum	lhoyum@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_17-879_Official
Julia	Jazynka	jjazynka@energyfreedomcoalition.com	Energy Freedom Coalition of America	101 Constitution Ave NW Ste 525 East Washington, DC 20001	Electronic Service	No	OFF_SL_17-879_Official
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2265 Roswell Road Suite 100 Marietta, GA 30062	Electronic Service	No	OFF_SL_17-879_Official
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official
Brendan	Jordan	bjordan@gpisd.net	Great Plains Institute	2801 21st Ave S., Suite 220 Minneapolis, MN 55407	Electronic Service	No	OFF_SL_17-879_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Mark J.	Kaufman	mkaufman@ibewlocal949.org	IBEW Local Union 949	12908 Nicollet Avenue South Burnsville, MN 55337	Electronic Service	No	OFF_SL_17-879_Official
Thomas	Koehler	TGK@IBEW160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	OFF_SL_17-879_Official
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official
James D.	Larson	james.larson@avantenergy.com	Avant Energy Services	220 S 6th St Ste 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_17-879_Official
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_17-879_Official
Ryan	Long	ryan.j.long@xcelenergy.com	Xcel Energy	414 Nicollet Mall 401 8th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_17-879_Official
Susan	Ludwig	sludwig@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_17-879_Official
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	OFF_SL_17-879_Official
Nick	Mark	nick.mark@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_17-879_Official
Kevin	Miller	kevin.miller@chargepoint.com	ChargePoint, Inc.	254 E. Hacienda Avenue Campbell, California 95008	Electronic Service	No	OFF_SL_17-879_Official
Herbert	Minke	hminke@allete.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_17-879_Official
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_17-879_Official
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_17-879_Official
Michael	Noble	noble@fresh-energy.org	Fresh Energy	Hamm Bldg., Suite 220 408 St. Peter Street St. Paul, MN 55102	Electronic Service	No	OFF_SL_17-879_Official
Debra	Opatz	dopatz@otpco.com	Otter Tail Power Company	215 South Cascade Street Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_17-879_Official
Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_17-879_Official
Jennifer	Peterson	jjpeterson@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_17-879_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Marcia	Podratz	mpodratz@mnpower.com	Minnesota Power	30 W Superior S Duluth, MN 55802	Electronic Service	No	OFF_SL_17-879_Official
David G.	Prazak	dprazak@otpco.com	Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_17-879_Official
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	OFF_SL_17-879_Official
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_17-879_Official
Thomas	Scharff	thomas.scharff@versoco.com	Verso Corp	600 High Street Wisconsin Rapids, WI 54495	Electronic Service	No	OFF_SL_17-879_Official
Larry L.	Schedin	Larry@LLSResources.com	LLS Resources, LLC	332 Minnesota St, Ste W1390 St. Paul, MN 55101	Electronic Service	No	OFF_SL_17-879_Official
Inga	Schuchard	ischuchard@larkinhoffman.com	Larkin Hoffman	8300 Norman Center Drive Suite 1000 Minneapolis, MN 55437	Electronic Service	No	OFF_SL_17-879_Official
Zeviel	Simpser	zsimpser@briggs.com	Briggs and Morgan PA	2200 IDS Center80 South Eighth Street Minneapolis, MN 554022157	Electronic Service	No	OFF_SL_17-879_Official
Anne	Smart	anne.smart@chargepoint.com	ChargePoint, Inc.	254 E Hacienda Ave Campbell, CA 95008	Electronic Service	No	OFF_SL_17-879_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	OFF_SL_17-879_Official
Byron E.	Starns	byron.starns@stinson.com	Stinson Leonard Street LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official
James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_17-879_Official
Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company	215 S Cascade St PO Box 496 Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_17-879_Official
Karen	Turnboom	karen.turnboom@versoco.com	Verso Corporation	100 Central Avenue Duluth, MN 55807	Electronic Service	No	OFF_SL_17-879_Official
Andrew	Twite	twite@fresh-energy.org	Fresh Energy	408 St. Peter Street, Ste. 220 St. Paul, MN 55102	Electronic Service	No	OFF_SL_17-879_Official
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_17-879_Official
Darrell	Washington	darrell.washington@state.mn.us	DOT	N/A	Electronic Service	No	OFF_SL_17-879_Official
Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine	225 South Sixth Street, Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Cam	Winton	cwinton@mnchamber.com	Minnesota Chamber of Commerce	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_17-879_Official
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	No	OFF_SL_17-879_Official
Patrick	Zomer	Patrick.Zomer@lawmoss.com	Moss & Barnett a Professional Association	150 S. 5th Street, #1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-879_Official

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1214

In the Matter of:	)
Application of Duke Energy Carolinas,	)
LLC for Adjustment of Rates and	)
Charges Applicable to Electric Service	)
in North Carolina	)

DIRECT TESTIMONY OF
JUSTIN R. BARNES
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT JRB-8

SCHEDULE 26 (N)
LARGE DEMAND GENERAL SERVICE (Continued)
(Secondary Voltage or at available Primary distribution Voltage)
(Single phase or three phase where available)(Demand Greater than 350 kW)

8. **CONJUNCTIVE DEMAND SERVICE OPTION:**
   a. The Conjunctive Demand Service Option (CDSO) is limited to nine (9) Customers taking Electric Service under this schedule. Each Customer must have at least two (2) but no more than five (5) Points of Delivery participating in this limited optional service. The total retail load served under this limited optional service (under both Schedule 26 and Schedule 31) is limited to 20 average megawatts. Customer Points of Delivery dedicated to electrified transportation are not limited with respect to number of Points of Delivery participating, nor size. Participating Points of Delivery must have begun taking Electric Service prior to January 1, 2018.
   b. Eligible Customers must have appropriate metering available for the participating Points of Delivery, as determined solely by the Company. Customer agrees that all participating Points of Delivery will be billed on the same billing cycle. This limited optional service is available beginning on or after January 1, 2021, starting with the first billing cycle of the participating Customer; and ending on the last billing cycle in December 2026. Participation is limited to a first-come, first-served basis. Customers may request potential participation in this limited optional service beginning at 8:00 a.m. July 1, 2020. Each Customer's participating load, at the time of requesting potential service, must not exceed 2 MW (of winter demand).
   c. Monthly Basic Charges, Energy Charges and Reactive Power Charges will be the same as noted in Sections 2 and 3 of this schedule. The Customer will pay a Delivery Demand Charge as noted in Section 8 of this schedule, in addition to the Conjunctive Maximum Demand Charge.
   d. The Conjunctive Maximum Demand will be determined by summing the Billing Demand metered at each of the Points of Delivery in each hour interval and then selecting the highest summation for the synchronized billing cycle. Should any meter fail to register correctly the amount of demand used by the Customer, the amount of such demand will be estimated by the Company from the best available information.

   e. **MONTHLY RATE – SECONDARY VOLTAGE:**
   Delivery Demand Charge:

OCT-MAR	APR-SEP	
$7.85	$5.23	per kW of Billing Demand

   Conjunctive Maximum Demand Charge:

OCT-MAR	APR-SEP	
$4.75	$3.17	per kW of Conjunctive Maximum Demand

(N)

(N)

SCHEDULE 31
PRIMARY GENERAL SERVICE (Continued)

(Single phase or three phase at the available Primary distribution voltage)

8. **CONJUNCTIVE DEMAND SERVICE OPTION:**
   a. The Conjunctive Demand Service Option (CDSO) is limited to five (5) Customers taking Electric Service under this schedule. Each Customer must have at least two (2) but no more than five (5) Points of Delivery participating in this limited optional service. The total retail load served under this limited optional service (under both Schedule 26 and Schedule 31) is limited to 20 average megawatts. Customer Points of Delivery dedicated to electrified transportation are not limited with respect to number of Points of Delivery participating, nor size. Participating Points of Delivery must have begun taking Electric Service prior to January 1, 2018.
   b. Eligible Customers must have appropriate metering available for the participating Points of Delivery, as determined solely by the Company. Customer agrees that all participating Points of Delivery will be billed on the same billing cycle. This limited optional service is available beginning on or after January 1, 2021, starting with the first billing cycle of the participating customer; and ending on the last billing cycle in December 2026. Participation is limited to a first-come, first-served basis. Customers may request potential participation in this limited optional service beginning at 8:00 a.m. July 1, 2020. Each Customer's participating load, at the time of requesting potential service, must not exceed 2 MW (of winter demand).
   c. Monthly Basic Charges, Energy Charges and Reactive Power Charges will be the same as noted in Sections 2 and 3 of this schedule. The Customer will pay a Delivery Demand Charge as noted in Section 8 of this schedule, in addition to the Conjunctive Maximum Demand Charge.
   d. The Conjunctive Maximum Demand will be determined by summing the Billing Demand metered at each of the Points of Delivery in each hour interval and then selecting the highest summation for the synchronized billing cycle. Should any meter fail to register correctly the amount of demand used by the Customer, the amount of such demand will be estimated by the Company from the best available information.

   e. **MONTHLY RATE**:

   Delivery Demand Charge:

OCT-MAR	APR-SEP	
$7.99	$5.33	per kW of Billing Demand

   Conjunctive Maximum Demand Charge:

OCT-MAR	APR-SEP	
$4.35	$2.90	per kW of Conjunctive Maximum Demand

(N)

PLACE: Dobbs Building
Raleigh, North Carolina

DATE: Friday, December 1, 2017

TIME: 9:30 a.m. - 12:30 p.m.

DOCKET NO: E-2, Sub 1142

BEFORE: Chairman Edward S. Finley, Jr., Presiding
Commissioner Bryan E. Beatty
Commissioner ToNola D. Brown-Bland
Commissioner Jerry C. Dockham
Commissioner James G. Patterson
Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

DUKE ENERGY PROGRESS, LLC

Application for Adjustment of Rates and Charges
Applicable to Electric Utility Service
in North Carolina.

VOLUME: 13

Noteworthy
Reporting Services, LLC

T A B L E   O F   C O N T E N T S

E X A M I N A T I O N S

spend the money for a cap in place, that you would expect to have an improvement of groundwater quality over time. And that simply -- that simply doesn't happen when you have wastes that are saturated. So therefore, you know, is it reasonable to spend the money to cap a surface impoundment knowing that you are going to have continued leaching of constituents to the groundwater, just like you do now, even before the cap? Doesn't seem like a reasonable action plan, and the efficiency of the money -- or the effectiveness of the money spent for a remedial measure, long term.

MR. QUINN: No more questions. Thank you.

CHAIRMAN FINLEY: All right. Questions by the Commission?

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Mr. Quarles, this may be in the materials, but you're probably more familiar with it than I am, so I will ask you the question.

The specific design of the closure plant at Roxboro and Mayo, does that include any engineered elements to divert groundwater flow -- future groundwater flows from upgradient?

A. It does not. There is nothing to prevent that lateral flow of groundwater.

Q. Thank you.

A. The other thing that I might add, as it relates to Roxboro, is the east impoundment -- or the east basin has an engineered landfill on top of the original ash impoundment, and that landfill has a liner and leachate collection system that is collecting this leachate that would otherwise infiltrate into the ground. What is interesting is that they take that leachate from that dry landfill on top of these basin and put that same leachate into the unlined basins of the east and west. So in the effort of protecting groundwater from this dry landfill on top of the east basin, they take that leachate and put it into unlined surface impoundments.

CHAIRMAN FINLEY: Ms. Brown-Bland.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. Good morning. Going back historically, when a location would be agreed upon for a plant, they would have considered the ability for storage and how the ground would receive that, et cetera; was there a thinking in the science of it at the time, that that was addressing safety issues?

A. You know, when I look at historical

documents, it's interesting, the industry recognized the likelihood that these ponds would leak, and they also recognized that -- that constituents, such as arsenic, for example, were harmful to people and were harmful to fish and aquatic life. So, on one hand, they recognized the risk, but they also seemed to accept that that's the way that they are going to do it, and I can't answer or explain why, but that seems to be very common in the files that I have reviewed.

Q. And that's on the behavior of the power companies, right?

A. Correct.

Q. But beyond that, in academia and the scientific world, was there discussion -- are you aware of any discussion and study about those issues back when the unlined ponds were the standard state-of-the-art method?

A. Well, the 1988 report to Congress by the EPA was, you know, very good at talking about what the industry practices were, and I could -- it talked to how -- we had groundwater protection standards back then, and the report -- the EPA report talked about that, and how common it was that there would be an exceedance of a standard -- one or more standards at several power plants around the country. So they recognized the risk, but it -- I'm not aware of any other, you know, formal studies in the waste industry in the 1970s. The power industry has Utility Solid Waste Activity Group, what's called USWAG, which was an industry group where they studied different types of things, and there might have been an earlier report that I did not have access to that would talk about that.

Q. Are you aware in any literature or any study, outside of that, that the power companies did or that they paid for, that looked at or examined whether the unlined ponds were, in and of themselves, a safety tool?

A. I am aware of -- I'm aware of an industry report that was published in 2001 by the Electric Power Research Institute, EPRI. It is really a telling report, as it relates to the plan of cap-in-place, because it evaluated -- and this is an industry document -- it evaluated three different disposal sites that were unlined surface impoundments that were all capped in place. And it evaluated the effectiveness of the cap in place to improve groundwater quality . And one of them -- one cap in place did not result in any improvement of groundwater quality. And the unique characteristic of that site is that the ash was submerged in groundwater. All right. And so they concluded that the cap was, quote, unquote, a cap that had little or no effect on this process. Again, falling back to what I said in my direct testimony about the lateral inflow of groundwater, and then if you have 10s of feet of ash that's saturated, that cap is not going to result in improvement of the groundwater quality.

Q. What I'm trying to get at is, was there a time when -- when the knowledgeable people, the academia and the professors, those types, accepted that an unlined pond was, to some degree, a safety measure, and that that -- and then there was a theory supporting that, believing that it was, and then there was a point in time when, perhaps, that theory fell away or was disproven; is there any such thing as that?

A. No. I'm not aware of any industry documents or any EPA documents at that time. The only thing that I would say to that is that, clearly, the industry recognized a risk to groundwater contamination in the mid-'70s, otherwise, they wouldn't have changed their way of disposal, preferring the dry landfill as opposed to wet impoundment.

Q. So there was a change in advancement and knowledge that prompted -- as we do with everything, as we learn, we make changes; as we advance, we make changes; as we become better capable of doing certain things, we make changes; is that fair?

A. Yeah. That's fair to say too. And I think what I have kind of gathered in my years of reviewing thousands of files -- you know, state agency files, EPA files, discovery files, that sort of thing, is that sometimes you tend to not choose to line an impoundment or build a lined landfill if there is no regulation that requires you to do so, and you proceed, kind of, at your own risk, if you will. That was fairly common.

Q. All right. So from your testimony, you are indicating that excavation will, at some point in time, reduce or prevent the further contamination or reduce the contamination that exists?

A. That's correct.

Q. So at what point in time -- if we were to begin excavation, at what point in time would we see the benefit on both counts, prevention and reduction; how long would it take?

A. I have read reports of some instances where there has been post-excavation monitoring in the Carolinas, the east coast, related work from the Southern Environmental Law Center, where it talked about fairly quick improvement of groundwater quality after the excavation, removal, and safe disposal of the waste.

Q. When you say fairly quick, I assume some sort period of time?

A. I would say -- and I don't know the specific time frame, but it's certainly within months or years, because these excavations were just recently performed.

Q. So months or a few years?

A. As opposed to decades of --

Q. Would it be significant improvement during those early -- the early stage?

A. You would expect -- of course, there is a groundwater flow velocity that's associated with this, so there is contaminated groundwater that is already going to be beneath these basins that's going to have to take its natural flow direction towards the receiving stream, but when you remove that source of the contamination, you can only expect that the quality will improve.

Q. What do we know or what do you know about the -- during the process of removal, what happens to contamination as the excavation process is being carried out?

A. The contamination of the groundwater?

Q. That, as well as safety to human and animal life, et cetera, plant life.

A. So the safety -- when you excavate the material, you are going to take it -- or the utility will take it to a lined disposal unit, whether it's on site or off site. So therefore, it would be designed to be protective of groundwater. So when you remove that source of the contamination, now you have a reduction of the concentrations, because groundwater from upgradient directions is naturally going to flow beneath what used to be the surface impoundment on the way to the stream. So over time, there would be some interaction and dilution, if you will, of that groundwater that is interacting with the contamination that's underneath the surface impoundment.

Q. Would the excavation process, itself, cause any worsening of the contamination situation?

A. It shouldn't.

Q. The disturbing of the material, of the groundwater, of the surface water?

A. So if you have ash that's submerged in groundwater, you are going to have to dewater that ash to be able to excavate the ash. So then that dewatering process will require a certain degree of treatment of that water before it's discharged to wherever it's going, whether it's going to go to a receiving stream or to a wastewater treatment plant, for example. So to be fully protective of surface waters, you would need to ensure that the quality of the water that is being pumped out of the -- what used to be the old impoundment would meet the appropriate standards for water quality and discharge to a surface water.

Q. What do you know about the Company's decision to cap in place? Did you do any further study into the reasons they chose that?

A. I didn't, other than I know that they planned to cap in place, and they only planned to pump or remove just a small amount of water, as needed, to operate construction equipment and/or dewater the surface so that they could build a cap. That's the limit -- that was -- their closure plan was pretty basic.

Q. All right. But your look into this and your study was more from a distance, rather than interaction with the Company or understanding from their perspective?

A. Correct.

Q. All right. Thank you.

EXAMINATION BY CHAIRMAN FINLEY:

Q. Mr. Quarles, is boron a naturally-occurring element in the soils in places like Mayo and Roxboro?

A. Boron is naturally occurring, just like most, if not all, metals. They do naturally occur. And what's -- so the challenge, when you look at a closure process, or whether or not there is a groundwater contamination, is you have to you understand what is naturally occurring and what is not. So there is ways to look at whether or not the boron, or arsenic, or whatever is naturally occurring or related to leaching from the waste. So one process is to look at the upgradient wells in -- compared to the downgradient wells. And if it's naturally occurring, there is an opportunity for boron, or arsenic, or whatever to be in the upgradient wells.

So, you know, what I do is I evaluate that, but you have to be careful sometimes, because the upgradient wells -- let's recognize, these impoundments have been in operation for, what, 40, 50, 60 years. And so when you sluice water to an impoundment, it mounds the groundwater and creates a radial flow, and so part of that, if a well is on the upgradient side, in fact, could have been influenced and might be influenced by that mounding to have some of these leachable constituents in it.

But what we do is we could also look at other constituents to, kind of, look for the signature of whether or not the metals that naturally occur are indicative of coal ash. So I look at other things like sulphate, calcium. These are the things that, again, commonly occur, but they also -- there is a relationship many times between a concentration of boron and a concentration of sulphate.

Q. You mentioned the Electric Power Research Institute study. What was the date of that again?

A. 2001.

Q. Do you know the name of it?

A. Yeah. I think so.

(Witness peruses documents.)

It's called "Evaluation and Modeling of Cap Alternatives at Three Unlined Coal Ash Impoundments." This date is September 2001.

Q. My understanding is, of the sluicing process that you mentioned, that coal ash is transported from the generator, to the pond, to the impoundment, or the repository, whatever you want to call it, and the coal ash settles to the bottom, and the water on the top is discharged; is that right?

A. Yeah. And so the reason utilities sluice is to take an ash that's created at the boiler, then mix it with water, and then they pump it to a pond so that the solids can settle out, and then the water, some of it will evaporate, some of it seeps into groundwater, and then some of it overflows through a permitted, regulated what we call an outfall to a receiving stream.

Q. Is a technical name for the water that is discharged --

A. We call it effluent.

Q. It's been in different contexts. Effluent means one thing to me and wastewater means another thing to me. Is it sometimes called wastewater as opposed to effluent?

A. It's really kind of synonymous here, because actually, the water that's being discharged through a permitted outfall includes a lot more than just loose water. It could be miscellaneous lab waste, and floor drains, and truck washing areas, and that sort of thing.

Q. But within the people of expertise like you, sometimes that water is described interchangeably as effluent and wastewater?

A. Correct.

Q. I think there is another witness in the case that says that any landfall -- or landfill -- and I take that to mean a lined landfill as well as an unlined landfill - will leak; do you agree with that?

A. There is a potential for any landfill to leak, whether it's lined or not. And, you know, mistakes can happen during construction with even a composite-lined landfill. So they are not foolproof, but they are better than no liner at all.

Q. All right. Thank you.

EXAMINATION BY COMMISSIONER GRAY:

Q. Mr. Quarles, in your summary, you referred to the Kingston coal plant TVA issue.

What was the remediation taken on that facility?

A. It's a little bit different, in that it was a dike failure of an impoundment. So we ended up with ash in the river and ash floating downstream. And so the remediation there was to excavate that material. And most of it, I believe, was transported off site by rail to a landfill in Alabama.

Q. Is the TVA a federal agency?

A. It is.

Q. Who paid for the cleanup?

A. I don't know.

Q. Who would you think would have paid for it?

A. You know, I don't know if it came out of their operating budget, I don't know if they filed for an insurance claim, I don't know if they went for ratepayer reimbursement. I just don't know.

Q. Do you know how much it cost?

A. I don't.

Q. Thank you.

CHAIRMAN FINLEY: Questions on the Commission's questions?

EXAMINATION BY MR. RUNKLE:

Q. In a follow-up of Commissioner Brown-Bland's questions about when a utility may have known that there were better, less environmental -- there were better ways to handle the coal ash than the wet coal ash in an unlined landfill; do you remember those questions?

A. I do.

Q. Now, if a utility, like DEP, would -- knew or should have known sometime in the '70s, or in the '85 -- the '88 report, or 2001 time period, why would a utility, like DEP, continue with the wet, unlined landfills?

MR. BURNETT: Objection, Mr. Chairman. Calls for speculation.

CHAIRMAN FINLEY: Do you have an opinion on that?

THE WITNESS: I guess my opinion would be it's convenient and there is no regulatory standard saying they can't do that.

EXAMINATION BY MR. DROOZ:

Q. Mr. Quarles, you were asked about how long it would take after excavation of ash for contamination to resolve or disappear.

Is that -- is the answer to that question something that's gonna vary from site to site?

A. It is.

Q. If there is a groundwater plume that has gone beyond the compliance boundary and has a significant amount of constituent concentration and it's well above the allowed amount, will the time it takes to remediate be greater than if there is a small amount?

A. It is. The further it's migrated away, and the higher the concentration is, one would expect a longer time.

Q. And if there is a significant plume of contaminants off site, are there methods to help remediate that above and beyond just excavation?

A. There are technologies out there that you could use to capture and prevent that groundwater from flowing off site.

Q. Would extraction wells and treatment be one of those technologies?

A. That's certainly one of the technologies that's being used.

Q. Are there grout curtains or other technologies?

A. There are, yes.

Q. Thank you. That's all.

EXAMINATION BY MR. BURNETT:

Q. Mr. Quarles, what year was the federal Coal Combustion Residuals rule passed?

A. I don't remember the exact year, but it's two or three years ago.

Q. Okay. Recently, correct?

A. Recently, correct.

Q. And it's not your testimony that the passage of that CCR rule was the first time that the federal EPA discovered that utilities in the nation were using unlined wet ash basins, is it?

A. That's not the first discovery, correct.

Q. That's right. In fact, you just testified here that the EPA at least was studying the issues of CCRs and their impact on the environment as early as 1988, correct?

A. Correct.

Q. You'd also agree with me, though, that the EPA, while it may have been studying the impact of CCRs in the 1980s, it took definitive action to comprehensively regulate them, as you said, maybe as early as three years ago, maybe even sooner than that, correct?

A. Yeah. The Kingston spill was the trigger, if you will, that caused a more comprehensive review of disposal units around the country, in terms of dike stability and contamination potential.

Q. And I believe I just heard you say, in response to another question, an answer that makes me believe that you are not asserting that wet, unlined ash basins have been illegal or unauthorized in this country, correct?

A. You know, I'm not a lawyer, so I don't like to, you know, talk about legality of a surface impoundment. All I can say is that a recent case that I worked on in Nashville, U.S. District Court against TVA at the Gallatin facility, the judge ruled that the unlined surface impoundment was, in fact -- points were discharged to water of the state.

Q. That's right. But that judge is not the EPA, is he?

A. He's not.

Q. Yeah. What year was the Coal Ash Management Act passed in the state of North Carolina?

A. I don't know.

Q. Well, do you believe that, whatever year that was, that's the first time that the State of North Carolina or the North Carolina Department of Environmental Quality knew that there were unlined wet ash basins in the state?

A. I can't comment on that. Just purely speculating.

Q. Would that have been something that you might have wanted to look into before you testified today?

A. My scope of work was to really look at the practices relative to closure and performance standard, whether or not it met the federal CCR rule, which is the federal standard that the states are required to be at least as stringent as that.

Q. Okay. Thank you, sir.

MR. QUINN: Briefly, Mr. Chairman.

EXAMINATION BY MR. QUINN.

Q. My understanding is that the federal CCR rules came into effect in 2014; does that sound about right?

A. That sounds about right.

Q. Prior to 2014, were there any regulations on the way in which coal ash can be stored, that you are aware of?

A. You know, every state -- every state has an opportunity to regulate coal combustion waste. Like in the state of Tennessee, for example, they formalized, in the solid waste rules -- permit by rules for disposal of coal combustion waste. So for years there has been a regulation in place for the method. Now, recognizing that -- after the Kingston spill, they recognized that, perhaps, that wasn't stringent enough, and so they changed that and started requiring all disposal units to be, essentially, equivalent to what we call Subtitle D, which is a composite liner, leachate collection system, that sort of thing. So individual states may have had an opportunity to regulate, but there was no formal federal standard for which the states had to go by.

Q. So if there are no formal federal standards the states had to go by, is it fair to say, then, that compliance with industry standard is what the utility's duty is when is comes to storage of coal ash?

A. That's a fair statement.

Q. And you have testified prior about what industry standard was at that time, correct?

A. Correct.

Q. Okay. Additionally, do you know whether the CCR rules at the federal level were finalized only after a lawsuit against the EPA that it comply with its duties to regulate coal ash; do you have any knowledge of that?

A. No, I don't.

Q. Okay. You were also asked about whether or not you reviewed North Carolina's Coal Ash Management Act; do you recall that?

A. I do.
Q. Now, whether or not there is a North Carolina Coal Ash Management Act, Duke Energy Progress is still required to comply with the federal standards, the CCR rules, right?
A. Correct.
MR. BURNETT: Objection, Mr. Chairman. The witness testified he's not a lawyer, and Counsel is testifying with this line of questioning.
MR. QUINN: Mr. Quarles is an expert in the area of the management of coal ash. He is very familiar with the standards, as he's testified at the federal level. I think he can give an opinion on that issue.
CHAIRMAN FINLEY: He may give his expert but nonlegal opinion, if he has one.
BY MR. QUINN:
Q. Mr. Quarles --
CHAIRMAN FINLEY: Is there a question pending?
MR. QUINN: Yeah. Well, I'm gonna rephrase the question, just to make sure we clear up any issues.

BY MR. QUINN:

Q. In your experience as a geologist working with coal ash, do utilities -- do utilities have to comply with the federal CCR rules?

A. They do. And, in fact, they are making plans to comply right now. So their regulatory deadlines, one of which is development of the closure plans, and put them on publicly-available websites, and constructing sampling, growing, and monitoring programs, doing liner assessments, you know, to determine whether these surface impoundments are lined or not. So the wheels are turning, and the regulatory deadlines are -- you know, they are happening for sure.

Q. Mr. Quarles, I'm sure you are also familiar that there are groundwater standards that dictate that certain, say, boron, arsenic, whatever, cannot go above certain minimum standards in groundwater; are you aware of that?

A. I am.

Q. Okay. Now, whether or not there are -- there is a coal ash-specific rule prior to 2014, are utilities required to comply with those rules?

A. Groundwater protection standards have been around for as long as I have, you know, been in this business, since the mid-'80s. I mean, there is nothing new. In fact, the 1988 report talked about how it was common that groundwater protection standards were exceeded at coal combustion waste sites. So standards have been there, whether or not there is a formal regulation on how you are supposed to design, construct, and operate a disposal unit. There has still been the requirement that you have groundwater protection standards that are meant to protect human health in the environment.

Q. In your review of documents in preparation for your testimony, did you review any groundwater monitoring studies commissioned by Duke Energy Progress?

A. The -- no. The studies that I reviewed really were the comprehensive site assessments, which were comprehensive site assessments that were done on behalf of Duke Progress, I guess, in accordance with the CAMA requirements. And -- so they were good discussions where their consultants made the conclusions on what constituents exceeded standards or not.

Q. And those are site-specific, right, to Roxboro and Mayo?

A. They were.

Q. Okay. And in those comprehensive site assessment studies, were any exceedances of groundwater standards found?

A. There were.

Q. And the exceedances, were they for constituents of coal ash?

A. They were.

Q. And were they downgradient from the coal ash impoundments? In other words, were they -- if the groundwater was flowing in one direction, are they downgradient from the coal ash impoundment, such that the water would have flowed --

MR. BURNETT: Mr. Chairman, objection. Asked and answered, and also well beyond the scope of cross examination. Counsel, I believe, is just putting this witness now on a direct format, notwithstanding his previous testimony.

CHAIRMAN FINLEY: Well, I asked him about that, and he testified about it, and I think that is consistent with the questions by the Commission, so you may answer.

THE WITNESS: So the comprehensive site assessments were done by the independent consultant specific to each of the sites, and they were -- their conclusions were that coal combustion waste constituents were, in fact, in the groundwater migrating from the disposal units, and I agree with those conclusions.

MR. QUINN: No further questions.

CHAIRMAN FINLEY: We will, without objection, accept Mr. Quarles' exhibits into evidence, and you may be excused.

THE WITNESS: Thank you.

MR. QUINN: Thank you, Mr. Quarles.

(Whereupon, Quarles Exhibits 1 through 6 and 8 through 10 were admitted into evidence.)

CHAIRMAN FINLEY: NCJC witness is next.

MS. LUHR: North Carolina Justice Center, North Carolina Housing Commission, Natural Resources Defense Council, and Southern Alliance for Clean Energy calls Satana Deberry to the stand.

SATANA DEBERRY,

having first been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION BY MS. LUHR:

Q. Please state your name and business address

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QUARLES EXHIBIT 1

RESUME

Docket No. e-7, Sub 1214

Mark Quarles, P.G.
Senior Geologist, Nashville Branch Manager

Education

MBA Vanderbilt – Owen Graduate School of Management, 2001

B.S., Environmental Engineering Technology, Western Kentucky University, 1985

Professional Registration

Professional Geologist – Tennessee (#3834)

Professional Geologist – New York (#779)

Professional Geologist – Georgia (#2266)

Water Pollution Control Operator (Class II) - Massachusetts

GENERAL CAREER BACKGROUND

Mr. Quarles has provided consulting services to a variety of local, state, US EPA, and international regulatory programs for a diverse list of clients — including industrial manufacturers, law firms, municipal governments, commercial developers, and non-profit organizations. He has served as Client Manager, Project Manager, and Senior Geologist for projects in multiple states and has managed teams of geologists, chemists, natural resource specialists, environmental engineers, and environmental scientists.

Coal combustion waste experience has included investigations for over 100 coal combustion waste disposal sites across the United States, with a particular emphasis on these states: Alabama, Florida, Georgia, Illinois, Iowa, Kentucky, New York, North Carolina, South Carolina, and Tennessee. The work has evaluated disposal site designs, operation and monitoring programs, and closure plans relative to the US EPA RCRA Subtitle D, Coal Combustion Residuals Rule ("CCR Rule") and state-equivalent programs.

In addition to coal combustion wastes, Mr. Quarles has experience with environmental compliance programs associated with US EPA and state-equivalent standards for voluntary Brownfield programs, hazardous wastes (RCRA Subtitle C), corporate environmental audits, Superfund (CERLCA), municipal and industrial landfill siting and design (RCRA Subtitle D), due diligence property transactional standards (ASTM), wastewater and stormwater discharges (Clean Water Act), potable water supply (Safe Drinking Water Act), oil storage (Oil Pollution Control Act), threatened and endangered species (Endangered Species Act), dredge and Fill (404 Permits), sediment contamination, stream alternation permits, and wetlands.

Mr. Quarles has testified as a subject matter expert in Federal and State Courts, administrative hearings, and public hearings.

REPRESENTATIVE CCR PROGRAM EXPERIENCE

General CCR Rule Compliance

Mr. Quarles has evaluated site conditions and compared them to the technical standards associated with the CCR Rule and state-equivalent programs, in addition to standards established by the Electric Power Research Institute. The services have included expert opinion technical reports, expert testimonies, and comments at public hearings regarding Environmental Impact Statements, CCR Rule compliance, proposed investigations to define the nature and extent of contamination, proposed closure plans, and proposed corrective action measures.

BBJ GROUP

Electric Power Industry and Governmental Research
Mr. Quarles has used historical research dating to the 1970s by the Electric Power Research Institute, the US EPA, internal utilities, peer-reviewed publications, and governmental research organizations to determine coal-fired power plant operational standards and known risks to water quality.

Forensic Analyses
Mr. Quarles has reviewed historical reports, topographic maps, and aerial photographs to determine where historical disposal operations occurred, the likelihood of wastes being placed below the seasonal high groundwater table, and when groundwater contamination mostly likely occurred.

Utility Rate Case Support
Mr. Quarles has testified at rate case hearings regarding compliance with the CCR Rule and state-equivalent programs. Services have included reviewing proposed investigations to identify legacy waste disposal activities, estimating when groundwater contamination most likely occurred, reviewing investigations to determine the nature and extent of contamination, and reviewing proposed groundwater corrective actions.

REPRESENTATIVE CCR PROJECT EXPERIENCE

CCR Rate Case Hearings – Raleigh, North Carolina
Served as Senior Geologist associated with rate casing hearings before the North Carolina Utilities Commission. Services included an extensive review of historical internal documents and discovery, proposed closure plans for landfills and surface impoundments, and groundwater monitoring plans relative to the CCR Rule and the Coal Ash Management Act.

CCR Compliance – Memphis, Tennessee
Served as Senior Geologist and subject matter expert reviewing site investigative activities associated with unlined surface impoundments along the Mississippi River. The primary concerns were arsenic in groundwater, the surface impoundments being located over the Memphis Sand Aquifer (a sole source public drinking water aquifer), and whether or not a confining layer existed to prevent downward migration.

CCR Compliance and Litigation – Gallatin, Tennessee
Served as Senior Geologist and litigation subject matter expert regarding CCR contamination of groundwater, surface and groundwater used as public drinking water supplies, connectivity of groundwater to surface waters, off-site contamination of river sediments, and leaching of constituents with the proposed cap-in-place closure. Forensic investigations demonstrated that wide-spread karst conditions of

sinkholes and sinking streams exist beneath the impoundments, impounded conditions have raised the localized groundwater, wastes have been submerged in groundwater, and continued leaching would occur with the proposed closure-in-place.

Remedy Selection – Multiple Locations, Illinois
Served as Senior Geologist to evaluate proposed remedies required by the Illinois Pollution Control Board at four power plants. The work included a review of site investigative activities and historical aerials to understand the extent of the wastes — information needed to select a remedy.

CCR Rule Compliance – Multiple Sites, Iowa
Served as Senior geologist to review surface impoundment and landfill historic construction documents, groundwater monitoring reports, alternate source determinations, and / or proposed groundwater remedies at eight power plants.

CCR Compliance and Litigation – Kingston, Tennessee
Served as Senior Geologist and field sampling team member in response to a dike failure that released 5.4 million cubic yards of coal combustion wastes into the Emory, Clinch, and Tennessee Rivers. Services included reviewing defendant discovery documents and field sampling results and completing surface water and private property sampling (including polarized microscopic analyses).

CCR NPDES Permit Comments – Ithaca, New York
Reviewed a proposed NPDES permit for a leachate and stormwater collection pond associated with a Part 360 landfill permit.

CCR Environmental Impact Statement – Kingston, Tennessee
Reviewed an EIS associated with a proposed bottom ash dewatering system. Compared the proposed plan to other utility-owned power plants and systems for water minimization, waste avoidance, and land disposal.

CCR Compliance and Litigation – Eden, North Carolina
Served as Senior Geologist and litigation subject matter expert regarding the nature and extent of contamination due to the failure of an unlined CCR surface impoundment. Services included an extensive review of historical industry practices and defendant discovery documents regarding construction, operation and maintenance, inspections, and the life expectancy of the underlying corrugated metal pipe that ultimately failed. Private property sampling was also completed.

Flue Gas Desulfurization (FGD) Landfill – Gallatin, Tennessee
Reviewed the Part 1 / 2 permit application for a proposed Subtitle D CCR

landfill. The services included a review of the hydrogeologic characterization plan, the proposed groundwater monitoring system, and the proposed landfill design regarding separation from the uppermost aquifer and leachate control.

CCR Impoundment Dewatering Plans – Multiple Locations, Georgia
Served as Senior Geologist to review dewatering plans associated with closure of surface impoundments. The work included research regarding changes in water quality associated with standing water in the impoundments, pore water within the submerged solid wastes, and groundwater. Those results were then compared to the NPDES permits to understand likely compliance, expected changes in water quality over time, and protection of the receiving streams.

UTILITY-RELATED LEGAL TESTIMONIES

Michael Beck et al versus Duke Energy Carolinas and Duke Energy Business Services. North Carolina State Court. Written testimony regarding the Dan River Plant spill and damage to private property and the Dan River. 2019.

Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina before the North Carolina Utilities Commission on behalf of the Sierra Club. Written and oral testimonies. January 2018.

Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina before the North Carolina Utilities Commission on behalf of the Sierra Club. Written and oral testimonies. October 2017.

Joint Intervenors versus the Nuclear Regulatory Commission, Atomic Safety and Licensing Board Panel on behalf of the Southern Alliance for Clean Energy, the National Parks and Conservation Association, the Emory University Law Clinic, and the Everglades Law Center. Evidentiary hearing. Written and oral testimonies. 2017.

SELC on behalf of the Tennessee Clean Water Network and Tennessee Scenic Rivers Association versus Tennessee Valley Authority, US District Court, Middle District of Tennessee. Written and oral testimonies. 2017.

Tulane Environmental Law Clinic on behalf of the Town of Abita Springs (LA) and the Concerned Citizens of St. Tammany Parish, New Orleans, Louisiana. Office of Conservation evidentiary hearing. Written and oral testimonies. 2014.

PEER-REVIEWED PUBLICATIONS

Quarles, M. and Chris Groves, "Forensic Hydrogeology: Evaluating a Karst Critical Zone Enormously Altered by Coal Combustion Residuals," Geologic Society of America conference, Denver, Colorado, September 2016.

Quarles, M., "A Case Study in Karst Hydrogeology and Contaminant Fate and Transport," National Groundwater Association 51st Annual Convention and Exposition, December 1999.

Quarles, M. and Allen P. Lusby, "Enhanced Biodegradation of Kerosene-Affected Groundwater and Soil," 1994 Annual Conference of the Academy of Hazardous Materials Managers, October 1994.

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INVESTIGATIONS OF COAL ASH DISPOSAL

AND

ITS IMPACT UPON GROUNDWATER

DUKE POWER COMPANY

D. P. Roche
A. Gnilka
J. E. Harwood

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Investigations of Duke Power Coal Ash Disposal and Its Impact Upon Groundwater

Executive Summary

Beginning in 1978, field and laboratory investigations of the composition of coal ash leachate and its behavior in the disposal environment were conducted by Duke Power and outside contractors. Leach tests, using EPA and ASTM protocals, were conducted on dry fly ash and bottom ash from the Allen, Belews Creek, and Marshall plants, as well as on ponded ash from all ash storage basins. All results found the concentrations of toxic metals in the ash to be non-hazardous according to the EPA criterion. Groundwater monitoring, in 13 test wells installed by Duke Power around a retired and active ash basin, found over a four-year period that drinking water quality was maintained in the wells downgradient of the sites after groundwater stabilization had occurred following well installation. Additional groundwater monitoring and soil testing from the same sites, done by an EPA contractor, also found the downgradient groundwater to be drinking water quality and suggested the high ion exchange capacity of the soil lining the ash basin to be the mechanism preventing migration of soluble metals from the ash basin. These field and laboratory studies confirm that wet disposal of coal ash by Duke Power has no significant impact on groundwater.

Investigations of Duke Power Coal Ash Disposal and Its Impact Upon Groundwater

Introduction

In 1983, the burning of 14,800,000 tons of bituminous coal at Duke Power's eight fossil stations produced 1,213,000 tons of fly ash and 409,000 tons of bottom ash. Except for 68,500 tons of fly ash (in cement and filler applications) and 51,000 tons of bottom ash (lightweight aggregate) sold that year for reuse, all of the coal ash was disposed of by sluicing to storage ponds ranging in size from 14 to 500 acres surface area. The ponds have NPDES permits for discharge of the supernatant water to receiving waters via an overflow tower. While permit effluent limitations have historically been complied with for the pond discharges to surface waters, the question of any leaching of ash constituents to groundwaters was raised in 1978 in light of the increased scrutiny by regulatory agencies. Since that time Duke Power has conducted groundwater monitoring and leachate testing to resolve this issue.

Because Duke's two largest fossil stations, Marshall and Belews Creek, are beginning conversion in 1984 from sluicing and ponding of fly ash to dry collection in silos and landfilling, the question of fly ash leachate will be less relevant to Duke as over 60% of the fly ash produced by the Company will be handled dry, compacted, and landfilled. This disposal method will greatly reduce any leaching of fly ash. However, prior to this change in disposal method, the lack of adverse effects of ash leachate even in the pond environment had been demonstrated. This report provides the results of ash leaching tests for all Duke fossil stations, and extensive and intensive groundwater monitoring at Plant Allen, conducted by Duke and by outside consultants.

Ash Leachate Analyses

The Environmental Protection Agency Extraction Procedure (May 19, 1980 Federal Register) calls for addition of distilled water equal to 16 times the weight of the solid (100 gms.), pH adjustment to 5.0 ±0.2 using 0.5 N acetic acid, and agitation for 24 hours. The sample is then filtered through a .45 micron membrane and the filtrate is diluted to 20 times the initial weight of the solid (2000 ml. for 100 gms.). The leachate is then preserved by acidification to pH 1.4 to 2.0 using nitric acid and is analyzed for eight toxic metals: arsenic, selenium, barium, cadmium, chromium, lead, mercury, and silver.

The American Society for Testing and Materials (ASTM, Committee D-34) has recommended a shaker method for extraction of solid waste for leachate analysis. The method calls for a 4:1 liquid/solid ratio and a 350 gm. solid sample, rather than the 16:1 ratio and 100 gm. sample required by EPA. The sample is shaken using a shaker table for 48 hours, with no pH adjustment. The sample is filtered and preserved as described above, but the filtrate is not diluted.

Both the Extraction Procedure (EP) and ASTM method have been used to simulate leachate from Duke fly and bottom ash, both in the dry and ponded state. These results have been compared to the EPA toxicity criterion limits for a solid waste under the Resource Conservation and Recovery Act (RCRA), which are:

Element	Concentration (ppb)
Arsenic	5,000
Selenium	1,000
Barium	100,000
Cadmium	1,000
Chromium	5,000
Lead	5,000
Mercury	200
Silver	5,000

Initially (in 1980), Duke Power analyzed samples of ponded ash (mostly bottom ash combined with some fly ash) by the EP procedure for all ash ponds. The results are shown in Table 1.

In the same time period, leach tests of dry fly and bottom ash at Belews Creek were conducted by consulting laboratories for the companies marketing the ash for reuse. Southeast Laboratories used the EP procedure to obtain the following results (in ppb) for bottom ash:

Table 1. Extraction Procedure Analysis of Ponded Ash from Duke Power Ash Basins. Samples collected in 1980.

All concentrations are in parts per billion.

	Allen	Belews	Buck		Cliffside	Dan River		Lee	Marshall	Riverbend	
			Cell 1	Cell 2		Cell 1	Cell 2			Cell 1	Cell 2
Arsenic	51	31	35	35	36	33	73	22	31	82	75
Barium	1200	1,100	2400	2200	1900	1300	2100	<1000	1100	1100	1300
Cadmium	<25	30	<25	<25	<25	<25	<25	<25	<25	<25	<25
Chromium	10	70	50	50	60	30	80	100	70	20	60
Lead	<500	<500	<500	<500	<500	<500	<500	<500	<500	<500	<500
Mercury	0.11	0.11	0.2	0.18	0.44	2.2	0.17	2	<0.1	<0.1	<0.1
Selenium	<6	<6	<6	<6	<6	<6	<6	<6	<6	<6	<6
Silver	150	50	110	90	30	70	60	100	70	30	40

Arsenic	1.4
Barium	50
Cadmium	5
Chromium	20
Lead	10
Mercury	0.5
Selenium	0.8
Silver	10

The Georgia Institute of Technology also analyzed Belews Creek bottom ash for radionuclides and found 2.4 pCi/g Radium-226, which is well below the proposed EPA limit of 5 pCi/g.

Raba-Kistner Consultants performed both the EP and ASTM leach tests on Belews Creek fly ash. The results are shown in Table 2.

Also in 1980, as part of an ash pond investigation conducted by EPA (the A. D. Little, Inc., study) at Plant Allen, samples of dry ash from Units 1 and 3 were analyzed utilizing the EP. The results are shown in Table 3, along with a Ra-226 activity of 4.3 (Unit 1) and 4.2 (Unit 3) pCi/g.

Plant Allen fly ash, bottom ash, and coal were also tested in 1982 in a U. S. Department of Energy study by Versar, Inc. Samples were processed according to both the EP and ASTM methods. Duke split samples with Versar and did its own EP and ASTM leach tests for comparison. The DOE test results are shown in Table 4, and Duke's are given in Table 5.

Table 2. BELEWS CREEK

FLY ASH LEACHATE (ppb)

	ASTM	EPA EP	EPA Limits
pH	3.7	4.0	
Arsenic	500	<5	5,000
Barium	Not Determined	<500	100,000
Cadmium	100	<100	1,000
Chromium	115	<100	5,000
Cobalt	100	<100	
Copper	2050	600	
Iron	2000	300	
Lead	<1000	<1000	5,000
Manganese	200	100	
Mercury	Not Determined	<2	200
Nickel	300	200	
Selenium	50	<10	1,000
Silver	Not Determined	<100	5,000
Zinc	1050	300	

Source: Raba-Kistner Consultants

Table 3. Extraction Procedure Results for Plant Allen Fly Ash

RESULTS FROM INITIAL SAMPLE ANALYSES

SAMPLE INFORMATION

Utility Name: Duke Power
Plant Name: Plant Allen
Plant Location: Gaston, N.C.
Type of Sample: Fly Ash
Sampling Location: Unit 1, ESP
Date Sampled: July 16, 1980

RESULTS

Basis: These results are from analyses performed by Arthur D. Little, Inc. on grab samples obtained during the first visit to the site. The limitation on the confidence levels for both sampling and analyses are noted in the accompanying cover letter.

Concentrations of Elements Measured in EPA Extraction Procedure (Ref: Fed. Register, Vol. 45, (May 19, 1980), pp. 33127-33131)

Element	Concentration (microgram/L extract)
Arsenic	98±20
Barium (mg/L)	0.51±0.16
Cadmium	16±3
Chromium	<8
Lead	<1
Mercury	<2
Selenium	52±7
Silver	<2

Activities of Radioisotopes Measured In Solid Samples Ref: Fed. Register, Vol. 43, Dec. 18, 1978, pp. 59022-3; see cover letter for experimental details)

Isotope	Specifc Activity (picocurie/gram)
Radium-226	4.3±0.3

Table 3. (cont'd)

RESULTS FROM INITIAL SAMPLE ANALYSES

SAMPLE INFORMATION

Utility Name: Duke Power
Plant Name: Plant Allen
Plant Location: Gaston, N.C
Type of Sample: Fly Ash
Sampling Location: Unit 3
Date Sampled: July 16, 1980

RESULTS

Basis: These results are from analyses performed by Arthur D. Little, Inc. on grab samples obtained during the first visit to the site. The limitation on the confidence levels for both sampling and analyses are noted in the accompanying cover letter.

Concentrations of Elements Measured in EPA Extraction Procedure (Ref: Fed. Register, Vol. 45, (May 19, 1980) pp. 33127-33131)

Element Construction (microgram/L extract)

Arsenic 63±10
Barium (mg/L) 0.36±0.16
Cadmium 5±3
Chromium <8
Lead <1
Mercury <2
Selenium 8±2
Silver <2

Activities of Radioisotopes Measured In Solid Samples Ref: Fed. Register, Vol. 43, Dec. 18, 1978 pp. 59022-3; see cover letter for experimental details)

Isotope	Specific Activity (picocurie/gram)
Radium-226	4.2±0.4

Table 4. Extraction Procedure and ASTM Leach Test Results (ppb) for Plant Allen

Coal, Fly Ash, and Bottom Ash - Department of Energy Study

Sample	Arsenic	Barium	Cadmium	Chromium	Lead	Mercury	Selenium	Silver
Coal								
EP	<10	270	<0.5	1.1	1.6	<.05	33	<.05
ASTM	41	310	<0.5	1.0	4.3	<.05	<10	.8
Fly Ash-Unit 2								
EP	460	230	<0.5	1.1	1.6	.19	150	<.05
ASTM	100	330	1.1	90	6.5	.53	94	1.3
Fly Ash-Unit 5								
EP	310	210	1.7	<1.0	3.7	<.05	19	<.05
ASTM	180	480	1.2	90	6.5	<.05	40	.42
Bottom Ash-Unit 5								
EP	12	660	<0.5	<1.0	<1.0	<.05	10	<.05
ASTM	10	260	1.4	<1.0	<1.0	<.05	10	<.05

Table 5. ALLEN LEACHATE STUDY - Duke Power Results

Sample Description	Arsenic ppb	Arsenic mg/g	Barium* ppb	Barium* mg/g	Cadmium ppb	Cadmium mg/g	Chromium ppb	Chromium mg/g
Flyash, unit #2								
EPA #1	269.3	4.08×10^{-3}	219.83	3.33×10^{-3}	3.96	6.00×10^{-5}	4.97	7.54×10^{-5}
EPA #2	274.1	4.28×10^{-3}	228.43	3.56×10^{-3}	3.41	5.32×10^{-5}	7.61	1.19×10^{-4}
ASTM #1	72.74	2.68×10^{-4}	266.03	9.80×10^{-4}	7.76	2.86×10^{-5}	119.08	4.39×10^{-4}
ASTM #2	91.9	3.33×10^{-4}	211.13	7.65×10^{-4}	1.36	4.93×10^{-6}	126.02	4.57×10^{-4}
Flyash, unit #5								
EPA #1	417.9	6.62×10^{-3}	268.93	4.26×10^{-3}	5.95	9.43×10^{-5}	16.63	2.64×10^{-4}
EPA #2	441.9	6.89×10^{-3}	433.93	6.77×10^{-3}	6.49	1.01×10^{-4}	14.41	2.25×10^{-4}
ASTM #1	254.9	9.05×10^{-4}	332.53	1.18×10^{-3}	0.45	1.60×10^{-6}	85.77	3.04×10^{-4}
ASTM #2	202.2	8.17×10^{-4}	300.93	1.07×10^{-3}	1.21	4.29×10^{-6}	80.22	2.85×10^{-4}
Bottom ash, unit #5								
EPA	<2.0	$<3.07 \times 10^{-5}$	46.37	7.10×10^{-4}	<0.20	$<3.07 \times 10^{-6}$	<0.50	$<7.68 \times 10^{-6}$
ASTM	5.84	1.92×10^{-5}	98.33	3.24×10^{-4}	0.36	1.18×10^{-6}	<0.50	$<1.64 \times 10^{-6}$
Coal								
EPA #1	<2.0	$<3.12 \times 10^{-5}$	40.53	6.33×10^{-4}	0.20	3.12×10^{-6}	0.53	8.28×10^{-6}
EPA #2	<2.0	$<3.18 \times 10^{-5}$	46.23	7.36×10^{-4}	0.29	4.61×10^{-6}	<0.50	$<7.95 \times 10^{-6}$
ASTM #1	<2.0	$<7.52 \times 10^{-6}$	141.73	5.33×10^{-4}	0.72	2.71×10^{-6}	<0.50	$<1.88 \times 10^{-6}$
ASTM #2	<2.0	$<7.65 \times 10^{-6}$	170.93	6.54×10^{-4}	0.97	3.71×10^{-6}	0.67	2.56×10^{-6}

*Corrected for filter blank.

Table 5. ALLEN LEACHATE STUDY (CONT'D)

Sample Description	Lead ppb	Lead mg/g	Mercury ppb	Mercury mg/g	Silver ppb	Silver mg/g	Selenium ppb	Selenium mg/g
Flyash, unit #2								
EPA #1	<1.0	$<1.52 \times 10^{-5}$	<0.1	$<1.52 \times 10^{-6}$	0.51	7.73×10^{-6}	68.74	1.04×10^{-3}
EPA #2	<1.0	$<1.56 \times 10^{-5}$	<0.1	$<1.56 \times 10^{-6}$	0.11	1.72×10^{-6}	69.12	1.08×10^{-3}
ASTM #1	<1.0	$<3.68 \times 10^{-6}$	<0.1	$<3.68 \times 10^{-7}$	1.48	5.45×10^{-6}	426.60	1.57×10^{-3}
ASTM #2	<1.0	$<3.63 \times 10^{-6}$	<0.1	$<3.63 \times 10^{-7}$	0.62	2.25×10^{-6}	445.30	1.61×10^{-3}
Flyash, unit #5								
EPA #1	<1.0	$<1.58 \times 10^{-5}$	<0.1	$<1.58 \times 10^{-6}$	0.56	8.88×10^{-6}	<5.0	$<7.92 \times 10^{-5}$
EPA #2	<1.0	$<1.56 \times 10^{-5}$	<0.1	$<1.56 \times 10^{-6}$	0.28	4.37×10^{-6}	<5.0	$<7.80 \times 10^{-5}$
ASTM #1	<1.0	$<3.55 \times 10^{-6}$	<0.1	$<3.55 \times 10^{-7}$	0.45	1.60×10^{-6}	13.60	4.83×10^{-5}
ASTM #2	<1.0	$<3.55 \times 10^{-6}$	<0.1	$<3.55 \times 10^{-7}$	0.39	1.38×10^{-6}	13.97	4.96×10^{-5}
Bottom ash, unit #5								
EPA	<1.0	$<1.54 \times 10^{-5}$	<0.1	$<1.54 \times 10^{-6}$	0.68	1.04×10^{-5}	<5.0	$<7.68 \times 10^{-5}$
ASTM	<1.0	$<3.29 \times 10^{-6}$	<0.1	$<3.29 \times 10^{-6}$	1.19	3.92×10^{-6}	11.74	3.86×10^{-5}
Coal								
EPA #1	<1.0	$<1.56 \times 10^{-5}$	<0.1	$<1.56 \times 10^{-6}$	0.11	1.72×10^{-6}	8.01	1.25×10^{-4}
EPA #2	<1.0	$<1.59 \times 10^{-5}$	<0.1	$<1.59 \times 10^{-6}$	0.45	7.16×10^{-6}	6.90	1.10×10^{-4}
ASTM #1	<1.0	$<3.76 \times 10^{-6}$	<0.1	$<3.76 \times 10^{-7}$	0.11	4.14×10^{-7}	26.27	9.88×10^{-5}
ASTM #2	<1.0	$<3.83 \times 10^{-6}$	<0.1	$<3.83 \times 10^{-7}$	0.22	8.42×10^{-7}	26.27	1.01×10^{-4}

In 1983, Duke Power tested dry fly ash and bottom ash from Plant Marshall by the EP method (Table 6).

Table 6. Location: Marshall Steam Station Flyash and Bottom Ash Toxicity Leach (Extraction Procedure) Date: 9/23 & 29/83

Location Description

(Concentration)

	Arsenic µg/l	Barium mg/l	Cadmium mg/l	Chromium mg/l	Lead mg/l	Mercury µg/l	Selenium µg/l	Silver mg/l
Flyash 1-A 09-23-83	82	0.26	<0.014	<0.02	<0.14	<0.1	166	<0.012
Flyash 1-B 09-23-83	89	0.16	<0.014	<0.02	<0.14	<0.1	166	0.017
Bottom Ash 2-A 09-29-83	118	0.062	<0.014	0.18	<0.14	<0.1	3.8	0.017
Bottom Ash 2-B 09-29-83	75	0.074	<0.014	<0.02	<0.14	<0.1	4.1	0.014

Duke Power Groundwater Monitoring

A monitoring program more extensive than that required by RCRA has been in progress at the Allen Steam Station since 1978. This in-house program was designed to evaluate the performance of Duke's ash basins, and their effect on groundwater movement and water quality. Additional Information: Duke's Ash Basin Equivalency Demonstration, EPA's Fossil-Fired Exemption (Dietrich Letter), EPRI Report - Codisposal of Liquid and Solid Wastes from a Typical Coal-Fired Generating Unit.

The objectives of this monitoring program were:

1. Provide data for documenting the condition/quality of groundwater at the ash basin site;

2. Predict and assess the effects of ash basin leachates on the physical and chemical quality of adjacent groundwater;

3. Determine the projected length of time that a typical ash basin substrate can retain leachates; and

4. Predict/calculate the life expectancy of an ash basin <u>with</u> <u>respect</u> to ion exchange capabilities of underlying soils.

Results of this study will be used to:

1. Have groundwater quality data from our service area which may be quite different from the limited studies EPA will use for formulating regional/national groundwater quality standards for industrial waste ponds (i.e., ash basins, resin basins);

2. Participate at the state or regional level in the development of groundwater quality standards and resulting legislation; and

3. Address any future groundwater legislation by means of a strong technical data base such as was done with the Ash Basin Equivalency Demonstration.

Ash Basin History

Allen station is a five-unit, 1140 MW coal-fired steam plant located on Lake Wylie in North Carolina. Mill tailings, bottom ash, and fly ash derived from the processing and burning of coal are pumped via ash slurry lines to a series of ash basins. Development of the ash disposal site (Figure 1) began with area A, which first received fly ash from the plant in the late 1950s.

Area B contains ash that was dredged from area A in the early 1970s. In 1972-73, it was covered with 30-60 cm of earth fill and planted with a ground cover. Currently, ash sluiced from the plant is pumped directly to the ash basin designated as area C. The series of dikes around this area were completed in 1973 and the basin has been operational since then.

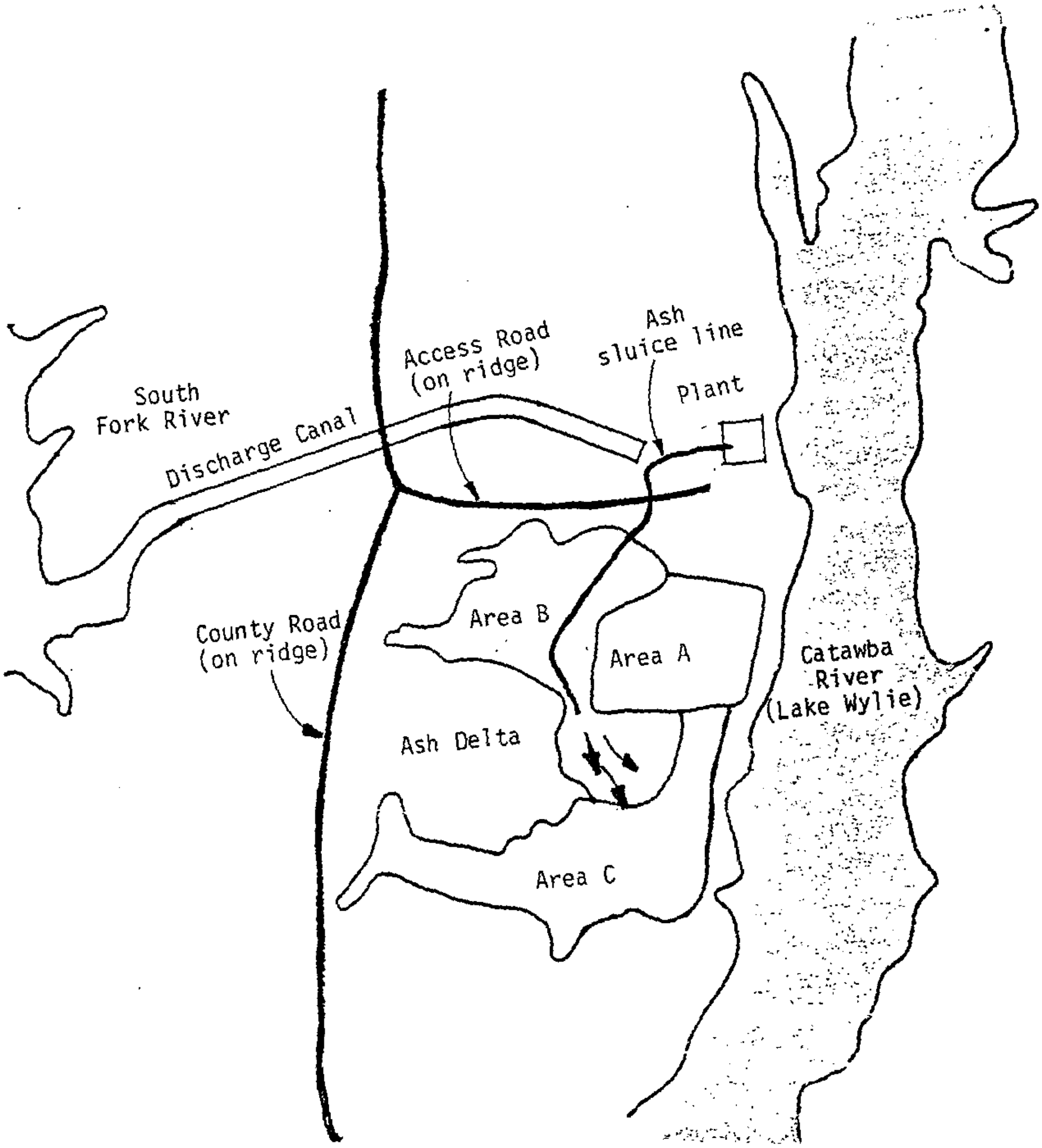

FIG. 1 - ALLEN ASH DISPOSAL SITE

These three areas typify the ash storage extremes that may exist around a steam station during the typical cycle of ash basin utilization and reclamation: stored ash generated in the plant's early days; dredge material less than 10 years old with limited reclamation; and currently generated ash. Note that the prevailing direction of movement of the groundwater is toward the river, as indicated by topographic relief in the plant vicinity (Figure 2). The series of ash basins are placed so that groundwater infiltration into the deeper acquifer is negligible, if not totally precluded. Additional Information: Allen Revegetation Study.

Well Construction

a. Layout-Physical Location/Site

Wells were located on the site based on an examination of available geological/historical/groundwater information. Field surveys were then conducted to select final well locations based on: 1) accessibility by drill rigs, 2) accessibility by well monitoring personnel, 3) placement in area which will not be disturbed by routine plant activities, 4) placement in areas not affected by future modifications of basin, 5) avoidance of unsuitable physical features, i.e., culverts, rock fill, avoid excessive clearing. The final well locations are indicated on Figure 2. Additional Information: Groundwater Monitoring Program.

b. Boring Logs

Extensive records were maintained to document all aspects of the actual well emplacement. Information included in the boring logs includes: date, well number, field, depths for sampling, soil field classification, general drilling procedures. Additional Information: See field logs of boring logs, Personal Communication: Jocassee Soils Lab; Construction personnel, DE Geologist, DE Civil Soils Engineers, Bowser-Morner, Law Engineering, Haley and Aldrich.

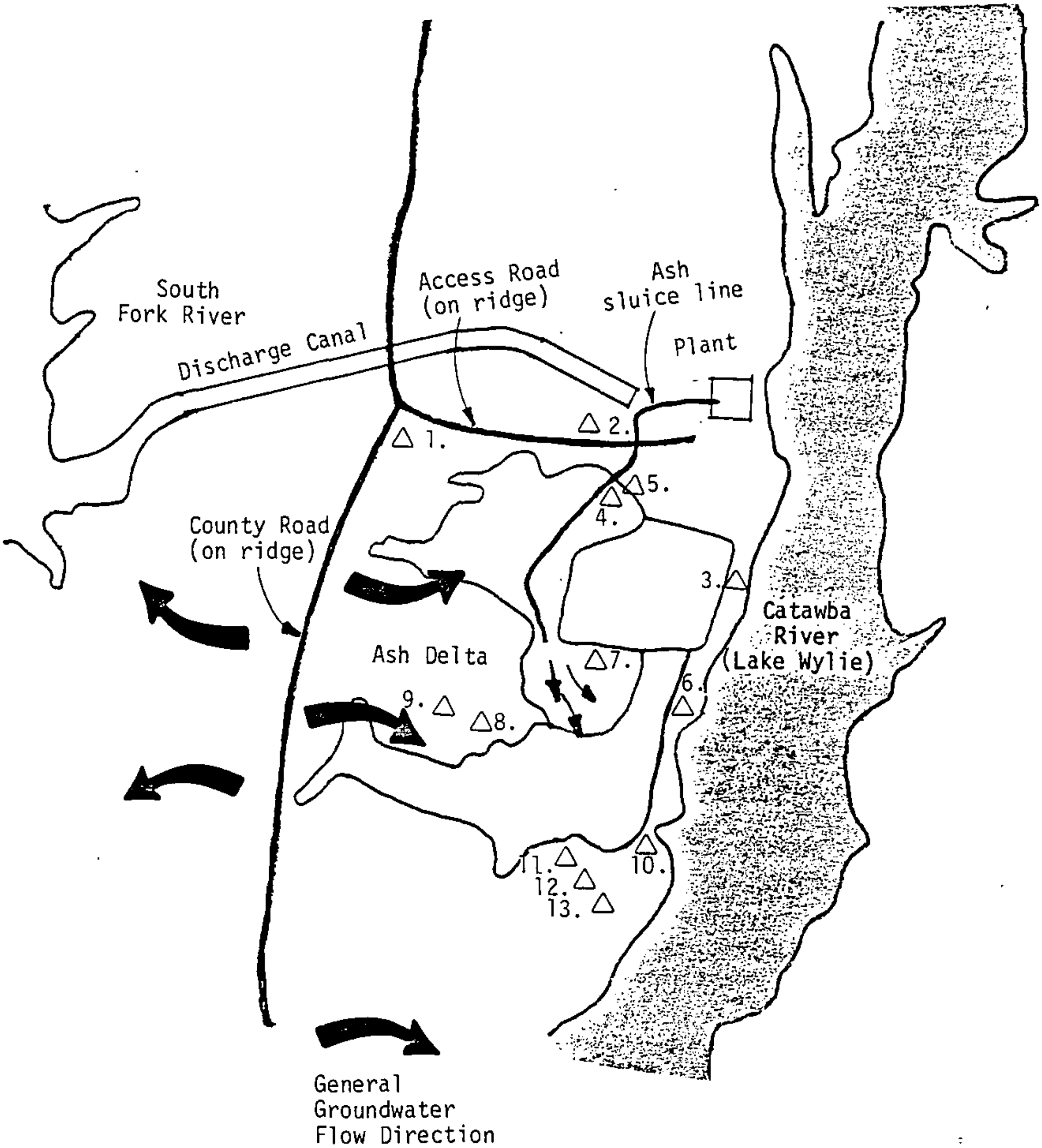

FIG. 2. - SAMPLING WELL LOCATIONS AT PLANT ALLEN

c. Soil Analyses

Soil analyses were conducted by the Jocassee Soils Laboratory. Additional Information: Results from Soils Lab are contained in separate appendix and include soil particle size analysis, grain size distribution, moisture, calculated permeabilities and soil descriptions. Results were discussed with Soil Lab personnel, Civil Engineering personnel, DE geologist, Haley and Aldrich, Weston, Inc., EPRI.

Well Design

a. Air Lift Sampler

The gas lift sampler (Figure 3) consists of two plastic tubes. The smaller tube (1/4 in. OD) supplies pressurized nitrogen from a regulated source to the discharge hole at the bottom of the gas line; the larger one (3/4 inc. OD) returns a gas-water mixture to the surface.

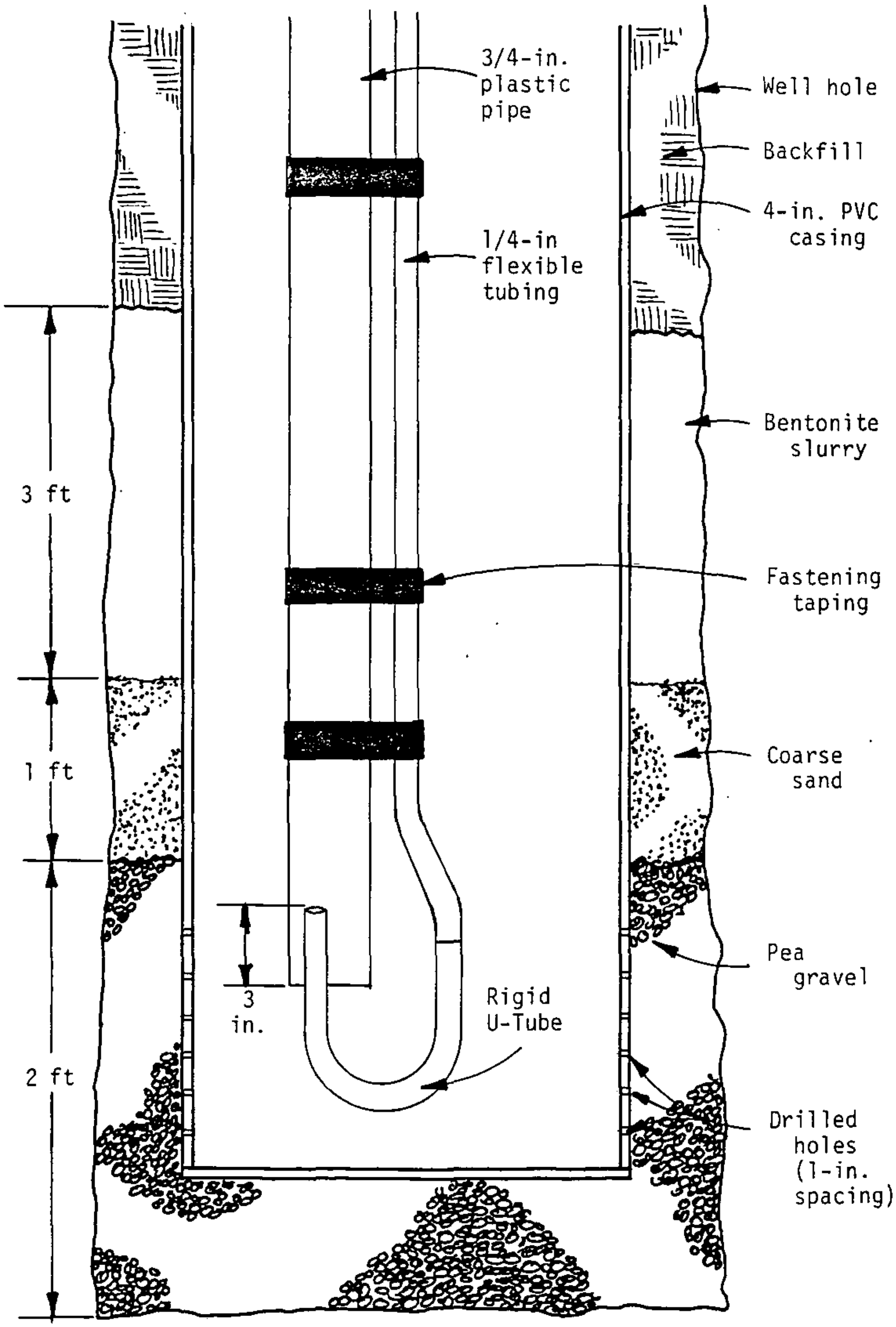

Figure 3. Schematic Diagram of gaslift sampler.

This assembly, constructed of PVC material, is inserted into a 4 inch PVC casing. The nitrogen feed line is connected to the inflow fixture and the gas is permitted to flow at a rate that produces the optimal water flow at the discharge tube. Samples are taken directly from the discharge tube opening.

b. Function of Wells

Table 7 lists the wells, general information and its function - control or monitoring. Additional information: Well installation log; surveyors log, site layout, soil boring data, general soils information, discussions with DE geologists, Civil Engineering personnel, Soils Laboratory personnel.

c. General Well Construction

All wetable surfaces of the well and associated piping and tubing were made of plastic to minimize potential metal contamination. Further details of well construction are contained in the air lift sampler description.

Sampling Procedure

a. Well Stabilization

Well installation was completed by February, 1978, and the wells were pumped using nitrogen on a weekly basis through April, 1978. This procedure ensured that drilling-related disturbances in the soil strata

Table 7. Function, location, and design details of wells.*

Well No.	Depth, ft.	Function and specifications
1	66	Control (to provide hydrological and chemical background data)
2	52	Control (same as well 1)
3	32	Monitoring; river side of old ash-basin dike, below perched-water table (nearest depth for ample groundwater volume)
5	47	Monitoring; finished to about 30 ft. below well 4
6	30	Monitoring; river side of new ash-basin dike, below perched-water table
7	43	Monitoring; on peninsula in new ash basin, finished below perched-water table
8	50	Control; northwest corner of new basin, finished below perched-water table
9	50	Control; farther west than well 8, below perched-water table
10	20	Monitoring; river side of dike of new ash-basin discharge
11	46	Monitoring; river side of south dike of new basin, sufficiently below table for ample groundwater sample
12	43	Monitoring; south and 30 ft. downgradient of well 11
13	40	Monitoring; south and 30 ft. downgradient of well 12

*Well #4 discontinued because of rerouting of ash discharge resulted in permanent lowering of water table.

had stabilized and that all water used during drill operations had been removed from the wells and surrounding soils. Conductivity measurements and spot sampling conducted during this period indicated that the wells had stabilized and a full-scale monthly sampling program was initiated.

b. Sampling Protocol

Wells were allowed to recharge prior to sampling (two-day survey) which eliminated any minor contamination from surface water infiltration, and ensured removal of waters that might be affected by different oxidation/reduction regimes as a result of exposure to the atmosphere. When these waters were removed, a more representative groundwater sample would be taken.

Although sampling initially consisted of monthly analyses, so little change was detected that quarterly sampling was deemed adequate. It should be noted, however, that in shallow wells - less than 3 m - the temperature was observed to change seasonally, even though the major chemical parameters showed no discernible trend. The procedure required that each well be pumped/sampled on two consecutive days. The wells were pumped to the lowest level possible on the first day, allowed to recharge for 24 hours, and then re-sampled. Temperature, pH, conductivity, and water level were measured in the field. Additional information: Groundwater Monitoring Program.

Analytical Procedure

a. Trace Metals

Composite samples were collected for laboratory analysis for the following: arsenic, cadmium, chromium, manganese, sodium, nickel, and zinc. The samples were put on ice and then brought to the lab where they were passed through a 0.45 μ filter (soluble fraction), transferred to acid washed glass bottles, and then acidified to a pH of approximately 2.0 with nitric acid. The maximum time between sample collection and completion of sample preservation was four hours.

The routine sample analysis consisted of calcium, chloride, magnesium, nitrate, potassium, sodium, sulfate, arsenic, cadmium, chromium, copper, iron, manganese, mercury, selenium and arsenic. Additional information: Sample study design, raw data sheets, various summaries in files.

b. Field Measurements

Sampling procedure for the field was as follows:

1) The depth to water in a monitoring well was measured using a volt-meter with calibrated coax cable and the value recorded on data sheets.

2) The 3/4 inch PVC tubing permanently mounted inside the 4 inch PVC casing was adjusted to a desirable pumping depth and this depth was recorded on field data sheets.

3) Pumping was started and the conductivity (μ mhos/cm^2) of the discharge water was monitored by a specific conductance bridge. The values for specific conductance at selected pumping times were recorded on a well pumping data sheet.

4) When conductivity reached a constant value, the temperature and pH of the discharge water were measured and values recorded on data sheets.

5) All field instruments were calibrated in the laboratory.

Summary of Analytical Results

The presence of leachate in the test wells was determined by comparing the concentration of substances present with those in the control wells and with the dissolved constituents in the old and new ash basins. Conductivities above 100 μmhos and calcium concentrations exceeding 8 mg/l were taken to indicate the presence of leachate. On this basis, wells 3, 4, and 11 were judged to be situated in the leachate plume.

For the first two years of data analyzed, the highest conductivity recorded for the control wells was 98 μmhos. By comparison, the lowest conductivity for the test wells in the plume was 180 μmhos. Average calcium concentration measured in the control wells was 2.62 mg/l, whereas the average for test wells 3, 4, and 11 was 54.5 mg/l. The elevated calcium levels were probably associated with the leading edge of the plume.

With the possible exception of test well 12, none of the other test wells appeared to be in the leachate plume. As shown in Figure 4, wells 11, 12 and 13 were situated on a hill sloping down to the river. Although well 11 is definitely situated in the plume, as mentioned, well 13 is not, because none of the parameters measured there exceeded those at the control wells. Well 12 is questionable, however, with average magnesium concentrations (2 mg/l) intermediate between those wells 11 and 13.

The concentration of trace elements in the control and test wells for the entire study is provided in Table 8, giving the single highest and lowest values recorded. For comparison, the table includes Interim Primary Drinking Water Standards.

As noted, minimum concentrations are generally near or at the detection limit of the instrumentation. In all cases, the minimum concentrations were less than the Interim Drinking Water Standards. Maximum values were observed during the early portion of the sampling period when water quality within the well was still influenced by the drilling process. Well No. 4 located at the ash/clay interface became dry during the last 2 years of the study because of

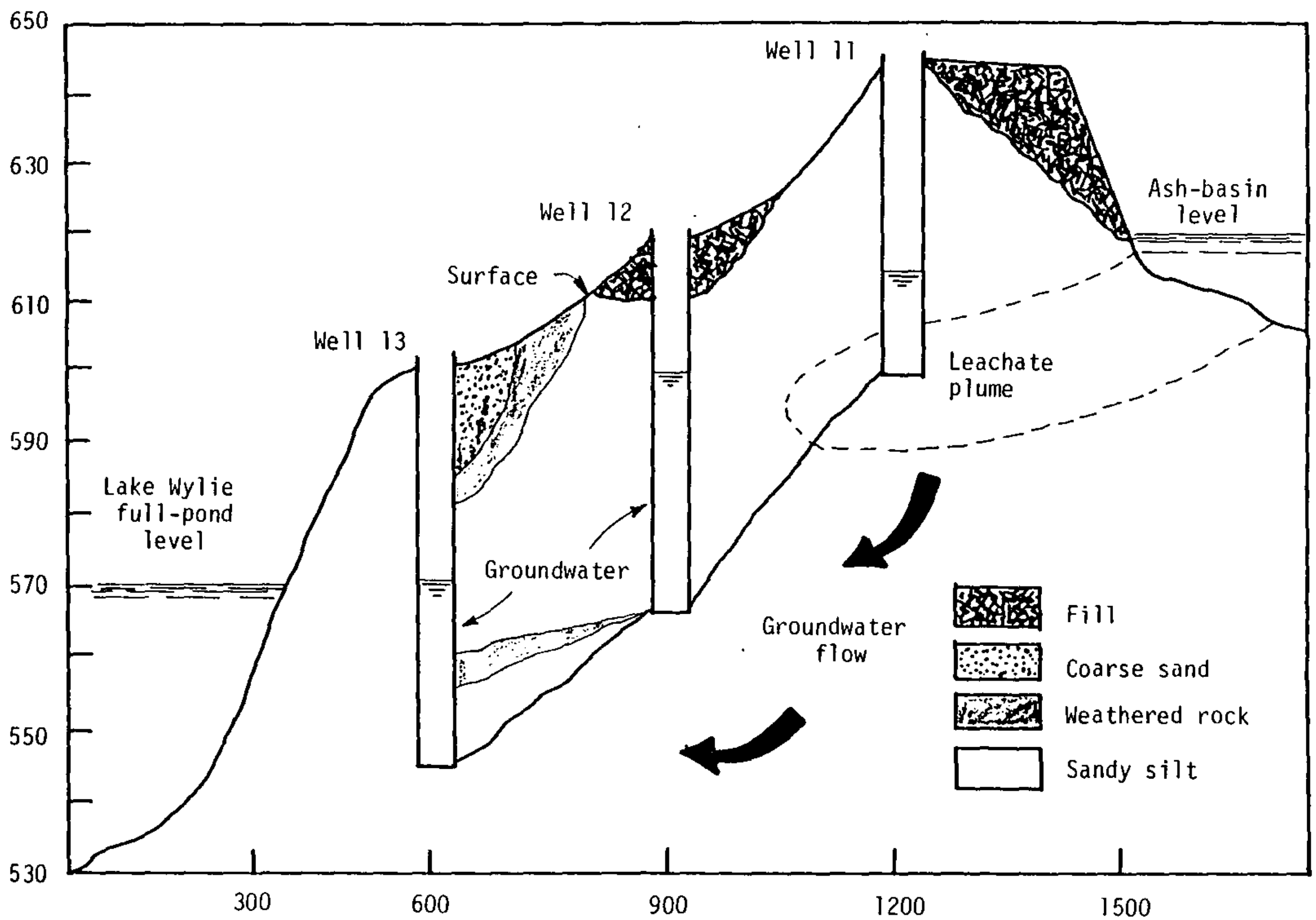

Figure 4. Horizontal movement of leachate plume is tracked over long term using calcium and conductivity data at wells 11, 12, and 13, placed downgrade from basin and each other

Table 8. Maximum - Minimum Concentrations (ppb) measured during groundwater sampling during 1979 - 1982 at Allen Steam Station.

Well No.	As Min - Max	Cd Min - Max	Se Min - Max	Cr Min - Max	Cu Min - Max	Ni Min - Max	Zn Min - Max
1	1.2 - <2.0	<0.2 - 0.3	<5.0 - 6.0	<0.5 - <20.0	<1.0 - <20.0	<5.0 - <20.0	1.2 - <20.0
2	2.0 - 6.5	0.7 - 1.1	<5.0 - 12.0	<0.5 - 90.0	1.8 - <10.0	<5.0 - 20.0	10.0 - 36.0
3	<2.0 - 9.2	<0.2 - 8.5	<5.0 - 8.5	<0.5 - 10.0	<10.0 - 30.0	<5.0 - 10.0	<1.0 - 70.0
4	8.8 - 112.5	<0.2 - 7.0	<5.0 - 19.5	<0.5 - 10.0	<1.0 - <10.0	<5.0 - 40.0	<1.0 - 80.0
5	<2.0 - 8.0	<0.2 - 7.0	<5.0 - 5.8	<0.5 - 20.0	<1.0 - <10.0	40 - 68.0	48 - 50
6	<2.0 - 2.0	<0.2 - 2.0	** - <5.0	0.7 - 10	<1.0 - <10.0	<5.0 - 20.0	4.1 - 20.0
7	<2.0 - 4.5	<0.2 - 3.5	<5.0 - 5.5	<0.5 - 10	<1.0 - <10.0	<5.0 - 10.0	11.0 - 20.0
8	<2.0 - 5.6	<0.2 - 15.0	** - <5.0	<0.5 - 20	<1.0 - <10.0	<5.0 - 10.0	1.7 - 20.0
9	1.3 - <2.0	<0.1 - *	** - <5.0	<0.5 - <20	<1.0 - <20.0	<5.0 - <20.0	<1.0 - <20.0
10	<2.0 - 6.8	7.6 - 19.0	<5.0 - 12.0	<0.5 - <20	<1.0 - <10.0	<5.0 - <10.0	8.0 - 20.0
11	<2.0 - 6.9	<0.2 - 7.7	<5.0 - 12.0	1.9 - 20	1.2 - 20.0	<5.0 - 20.0	6.6 - 90.0
12	<2.0 - 3.4	<0.2 - 7.0	<5.0 - 8.5	<0.5 - 20	<1.0 - <10.0	<5.0 - 10.0	11.0 - 30.0
13	<2.0 - 5.1	<0.2 - 2.8	<5.0 - 11.5	1.6 - 50	2.1 - 10.0	<5.0 - <10.0	2.2 - 30.0
EPA[1]	50	10	10	50	1000	NC[2]	5000

[1]- EPA Interim Primary Drinking Water Standards
[2]- No criterion
* - One sample only
** - Detection limit changed from <1.0 to <5.0

rerouting of ash sluice lines in the area. Consequently, these data reflect the quality of interstitial water in the ash pond rather than the actual groundwaters.

Environmental Protection Agency Contract No. 68-02-3167:
Characterization and Environmental Monitoring of Full Scale
Utility Waste Disposal Sites

Prime Contractor: Arthur D. Little, Inc.

Geotechnical Subcontractor: Bowser-Morner Testing Laboratories, Inc.

Chemical Analysis Subcontractor: TRW, Inc.

The purpose of this program was to obtain information to enable promulgation of federal regulations under RCRA for the storage, treatment, and disposal of coal ash and flue gas desulfurization sludge.

The study involved geohydrologic and ground water quality investigations at six utility waste sites. Soil borings were performed to take split spoon and Shelby tube samples and to install test wells. Flush joint, steel casing (4 inch ID) borings, using wash-boring techniques, were employed. Soil samples were obtained at 5 ft. intervals, with the split-spoon sampler used to determine Standard Penetration. Wells consisted of 2 in. ID, Schedule 80 PVC pipe with slotted well points surrounded to 5 ft. above the point with Ottawa sand. The casings were backfilled with sand, cement grouted at ground surface, and completed with a 3 ft. stand pipe with vented locking cap. Samples of dry fly ash were also taken for leachate analysis.

The Plant Allen site was selected as being representative of the Piedmont region and the combined ponding of fly and bottom ash. The site was also selected to investigate Duke Power's practice of treating boiler cleaning waste in the ash basin.

The geology of the Allen site was found to consist primarily of residual (silty clay with low organic content) soils with some very localized alluvial deposits from former surface drainage areas. The original groundwater table was located at a maximum depth of 33 ft. Groundwater flow was found to be 5 X 10^5 m^3/yr. The A. D. Little subcontractors decided upon 12 test wells to characterize the retired and active ash basins, in locations similar to those selected by Design Engineering for the Duke study. Two background wells (3-4 and 3-4A) were located upgradient from DP well #8, and seven downgradient wells were installed. Well 3-5 was placed near DP #11, Wells 3-6A and B near DP #10, Well 3-7 further upriver, Well 3-9 and 3-8A near DP #6 and Well 3-8 upriver and downgradient of the dike separating the retired and active basins. Well 3-1 was located within the retired pond and Wells 3-2 and 3-3 were placed in the active pond. Well 3-2 sampled the water in the ash at the bottom of the pond. In addition, the toe drains of the active pond dike were designated 3-10, 3-11, and 3-12, and the pond NPDES discharge was designated 3-13. The sampling locations are shown in Figure 5. All wells were flushed after installation and were subsequently sampled by peristaltic pump. Groundwater sampling occurred in February and March 1981 and in July 1982. Samples of boiler cleaning waste were taken during the cleaning of Allen #4 in November 1981.

Groundwater samples were analyzed by Inductively Coupled Argon Plasma emission spectroscopy, except for analysis of arsenic and selenium by hydride evolution atomic absorption and analysis of sulfate (and five other anions) by ion chromatography. Data for some selected parameters are shown in Table 9

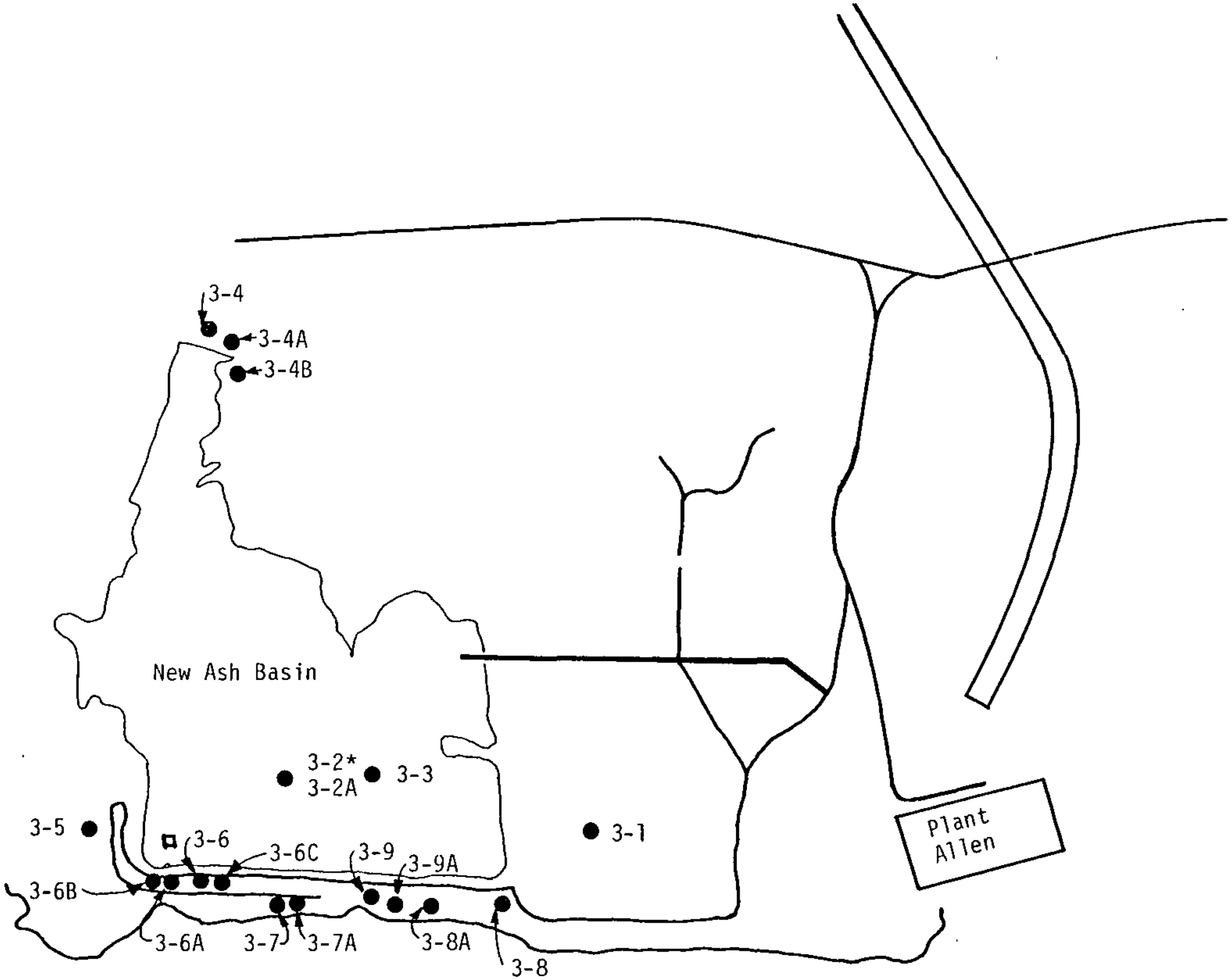

Figure 5. EPA/ADL Groundwater Monitoring Wells In-Place at Plant Allen as of June 30, 1982.

*3-2 - Depth at ash/clay interface
3-2A - Well point within the ash.

Table 9. Selected Groundwater Data for Plant Allen Sampling Location

DATE	February 1981		March 1981				July 1982			
Location	3-2	3-9	3-2	8	3-9	6	3-2	8	3-9	6
As (ppb)	1550	NA	2425	<2	<0.2	<2	318	<5	<0.1	NS (Inaccessible)
Se (ppb)	3	NA	<2	<5	<.26	<5	6.6	<5	<0.1	NS (Inaccessible)
Cu (ppm)	<.008	<.008	<.005	2.2	<.005	<1	<.008	<1	<.008	NS (Inaccessible)
Mg (ppb)	10.5	7.9	11.7	1.2	8.7	1.2	6	1.15	7.1	NS (Inaccessible)
SO_4 (ppm)	320	<4	320	NA	<4	NA	169	NA	4	NS (Inaccessible)

NS = Not Sampled
NA = Not Analyzed

for Wells 3-2 (worst case high concentrations) and 3-9 (downgradient of active pond) with some data from Duke wells 8 (background) and 6 for comparison. The parameters shown are arsenic and selenium (primary drinking water standards), magnesium (indicator of ion exchange capacity), and copper and sulfate (secondary drinking water standards). The difference in the concentration of arsenic and sulfate between that found within the active pond and in the downgradient well is noteworthy. The arsenic concentrations detected in the interstitial waters of the ash-soil interface at the bottom of the active pond (well 3-2) were much higher than the leachable arsenic found in dry fly ash from Allen Unit 1 (98 ppb) and Unit 3 (63 ppb), yet no arsenic was detected in well 3-9 downgradient of the active pond.

Soil attenuation is suggested by A. D. Little as the mechanism preventing migration of arsenic from the ponds. This was demonstrated by lab experiments in which interstitial water from well 3-2 (fortified with cadmium, chromium, copper, lead, and selenium) was used as a test leachate to be combined in 50-ml aliquots with .05, .5, 5, and 25 gms. of soil from the borings for 3-2. The slurries were shaken for 24 hrs., filtered through a .45 um filter, and aliquots were either preserved with nitric acid for ICAP or cooled for ion chromatography. Analyses were performed both on solutions and on digested solids.

Statistically significant decreases in concentration between starting solutions and equilibrated solutions were considered to be the quantity adsorbed by the soil. The starting solution concentrations of arsenic and selenium were 512 and 125 ppb, respectively. The alluvial soil used from the bottom of well 3-2 was 69% sand, 28% clay, 8% silt, with 0.08% total organic carbon and 4940 ppm manganese. The pH of the leachate/soil mixtures was 8.97 for the .05 gms. solution, 8.58 for .5 gms., 6.99 for 5 gms., and 6.5 for the 25 gms. solution.

The equilibrated final solutions contained as much as 360 ppb arsenic and 113 ppb selenium for the smallest amount of soil but as little as <0.2 ppb arsenic and 0.2 ppb selenium for the 25 gm. soil sample, indicating the soil's high adsorptive capacity, the highest of any site studied by A. D. Little. The high manganese content of the soil is suggested as the explanation for its ability to adsorb arsenic and selenium.

The soil from 3-2, the groundwater from the downgradient wells, and the pond toe drains and discharge water did not have concentrations of copper, nickel, and zinc above background, confirming that the high concentrations of these metals added to the pond during a boiler cleaning are precipitated and confined within the pond.

SIERRA CLUB

QUARLES EXHIBIT 3

1985 AD LITTLE WASTE REPORT EXCERPTS

Docket No. e-7, Sub 1214

I/A

EPA-600/7-85-028a
June 1985

PB85228054

FULL-SCALE FIELD EVALUATION OF WASTE DISPOSAL FROM COAL-FIRED ELECTRIC GENERATING PLANTS

Volume I. Sections 1 Through 5

by

Chakra J. Santhanam, Armand A. Balasco,
Itamar Bodek, and Charles B. Cooper

Arthur D. Little, Inc.
20 Acorn Park
Cambridge, MA 02140

EPA Contract: 68-02-3167

John T. Humphrey
Haley and Aldrich, Inc.
238 Main Street
Cambridge, MA 02142

Barry Thacker
Geologic Associates, Inc.
10628 Dutchtown Road
Knoxville, TN 37922

EPA Project Officer: Julian W. Jones
Air and Energy Engineering Research Laboratory
Office of Environmental Engineering and Technology
Research Triangle Park, NC 27711

AIR AND ENERGY ENGINEERING RESEARCH LABORATORY
OFFICE OF RESEARCH AND DEVELOPMENT
U.S. ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

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15. SUPPLEMENTARY NOTES AEERL project officer is Julian W. Jones, Mail Drop 61, 919/541-2489. (*)Haley and Aldrich, Inc., Cambridge, MA 02142. (**)Geologic Associates, Inc., Knoxville, TN 37922. Volume II is Section 6 through 9.

16. ABSTRACT The six-volume report summarizes results of a 3-year study of current coal ash and flue gas desulfurization (FGD) waste disposal practices at coal-fired electric generating plants. The study involved characterization of wastes, environmental data gathering, evaluation of environmental effects, and engineering/cost evaluations of disposal practices at six sites around the country. Study results provide technical background data and information for EPA, state and local permitting officials, and the utility industry for implementing environmentally sound disposal practices. Study data suggest that no environmental effects have occurred at any of the six sites; i.e., data from wells downgradient of the disposal sites indicate that waste leachate has resulted in concentrations of chemicals less than the EPA primary drinking water standards. A generic environmental evaluation--based on a matrix of four waste types, three disposal methods, and five environmental settings--shows that, on balance, technology exists for environmentally sound disposal of coal ash and FGD wastes for ponding, interim ponding/landfilling, and landfilling. For some combinations of waste types, disposal methods, and environmental settings, mitigation methods must be taken to avoid adverse environmental effects. Costs of waste disposal operations are highly system and site specific.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Pollution	Ashes	Pollution Control	13B	21B
Waste Disposal	Flue Gases	Stationary Sources		
Wastes	Desulfurization		14G	07A, 07D
Coal	Cost Engineering		21D	14A
Combustion				
Electric Power Plants			10B	

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ABSTRACT

This report summarizes results of a 3-year study of current coal ash and flue gas desulfurization (FGD) waste disposal practices at coal-fired electric generating plants. The study was conducted by Arthur D. Little, Inc., under EPA contract 68-02-3167, and involved characterizing wastes, gathering environmental data, assessing environmental effects, and evaluating the engineering/costs of disposal practices at six selected sites in various locations around the country. Results of the study are providing technical background data and information to EPA, State and local permitting officials, and the utility industry for implementing environmentally sound disposal practices.

Data from the study suggest that no major environmental effects have occurred at any of the six sites. For example, data from wells downgradient of the disposal sites indicate that the contribution of waste leachate to the groundwater has generally resulted in concentrations of chemicals less than the primary drinking water standards established by EPA. Although occasional exceedances of the standards were observed, these were not necessarily attributable to coal ash and FGD waste. A generic environmental evaluation based on a matrix of four waste types, three disposal methods, and five environmental settings (based on climate and hydrogeology) shows that technology exists for environmentally sound disposal of coal ash and FGD wastes for ponding, interim ponding/landfilling, and landfilling. For some combinations of waste types, disposal methods, and environmental settings, measures must be taken to avoid adverse environmental effects. However, site-specific application of good engineering design and practices can mitigate most potentially adverse effects of coal ash and FGD waste disposal. Costs of waste disposal operations are highly system- and site-specific.

TABLE OF CONTENTS

(*) All Volumes.
(**) Volume I starts.

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

(*) Volume II starts.

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

SECTION 5

RESULTS AND CONCLUSIONS FOR THE SIX STUDY SITES

5.1 OVERVIEW

This section summarizes the environmental assessment and engineering cost results for each of the six sites. Some of the significant, general, environmental assessment conclusions are that:

(1) Major dissolved species, especially sulfate, can be expected to migrate off-site, in exceedance of secondary drinking water standards, and remain unattenuated. However, in all cases except direct, upgradient hydrogeologic proximity to drinking water or a very small surface water body, such migration would have little environmental significance. This is because the elevated concentrations would prevail only in a fairly small area and are generally below damage thresholds. Thus, they would have few, if any, adverse ecological effects.

(2) Releases of most trace metals are generally within acceptable limits (e.g., drinking water and aquatic life standards), because of the combined effects of receiving water dilution and the chemical immobilization of most waste-related species. Arsenic is a significant exception that would require case-by-case evaluation for analogous wastes. In this study, elevated concentrations of arsenic in the in-situ liquid phase and/or off-site mobility of arsenic were observed at three of the six sites.

(3) In settings characterized by at least modest precipitation and fairly pervious soils where disposal occurs in direct hydrogeologic proximity to a subsurface drinking water supply or small, high-quality surface water body, an artificial disposal site liner may be needed to minimize contamination by (at least) the major species. A minimum liner thickness of about 0.5 m (1.5 ft) would suffice for proper engineering placement of soil-like liners.

(4) Isolated areas of high-quality surface or groundwater may be expected at disposal site settings where most of the ambient water is highly mineralized. This phenomenon was observed

in the highly mineralized western and acid-mine drainage settings studied in this program.

(5) In many cases, adverse environmental water quality impacts that may occur can be adequately mitigated by careful location of the disposal site. Areas with less permeable and more chemically attenuative soils are preferable, as are locations that are removed from drinking water supplies or key small surface water bodies.

The results and conclusions are discussed in more detail below for each individual site studied in this program.

5.2 PLANT ALLEN

5.2.1 Site Description

5.2.1.1 Background--
Plant Allen of Duke Power Company is located in Gaston County, North Carolina, four miles southeast of the town of Belmont. The plant site is adjacent to the west bank of Lake Wylie, one of eleven impoundments that comprise the 386 km (240 miles) Catawba River Development. The site location is shown on Figure 5.1.

The coal ash disposal site at Plant Allen consists of two separate, major units. The first unit is comprised of retired ash ponds, approximately 206,000 m^2 (127 acres) in total area, that were used and expanded from 1957 to 1973. The second unit is the active ash pond, approximately 239,000 m^2 (146 acres) in area, that was constructed in 1973. A combination of fly ash and bottom ash is presently sluiced directly into this pond located immediately south of and adjacent to the retired pond complex. The liquid overflow from the ash pond is discharged untreated into adjacent Lake Wylie. The ash ponds are retained by earth dikes constructed from residual soils excavated from within the ash pond limits.

The following factors were important in the selection of the combined fly ash/bottom ash disposal ponding operation at Plant Allen for study:

- The practice of pond disposal of combined fly ash and bottom ash is the most common FGC waste disposal practice in the United States and virtually the only disposal practice in the Piedmont Region.

- The amount of precipitation and the mix of residual and alluvial soils at the Plant Allen site represent environmental conditions typical of many other locations in the eastern half of the United States and are particularly representative of the Piedmont Region, which supports significant coal-fired generating capacity.

- Co-disposal of intermittent, contaminant-rich waste streams (i.e., boiler cleaning wastes and coal pile run-off) in ash ponds occurs at

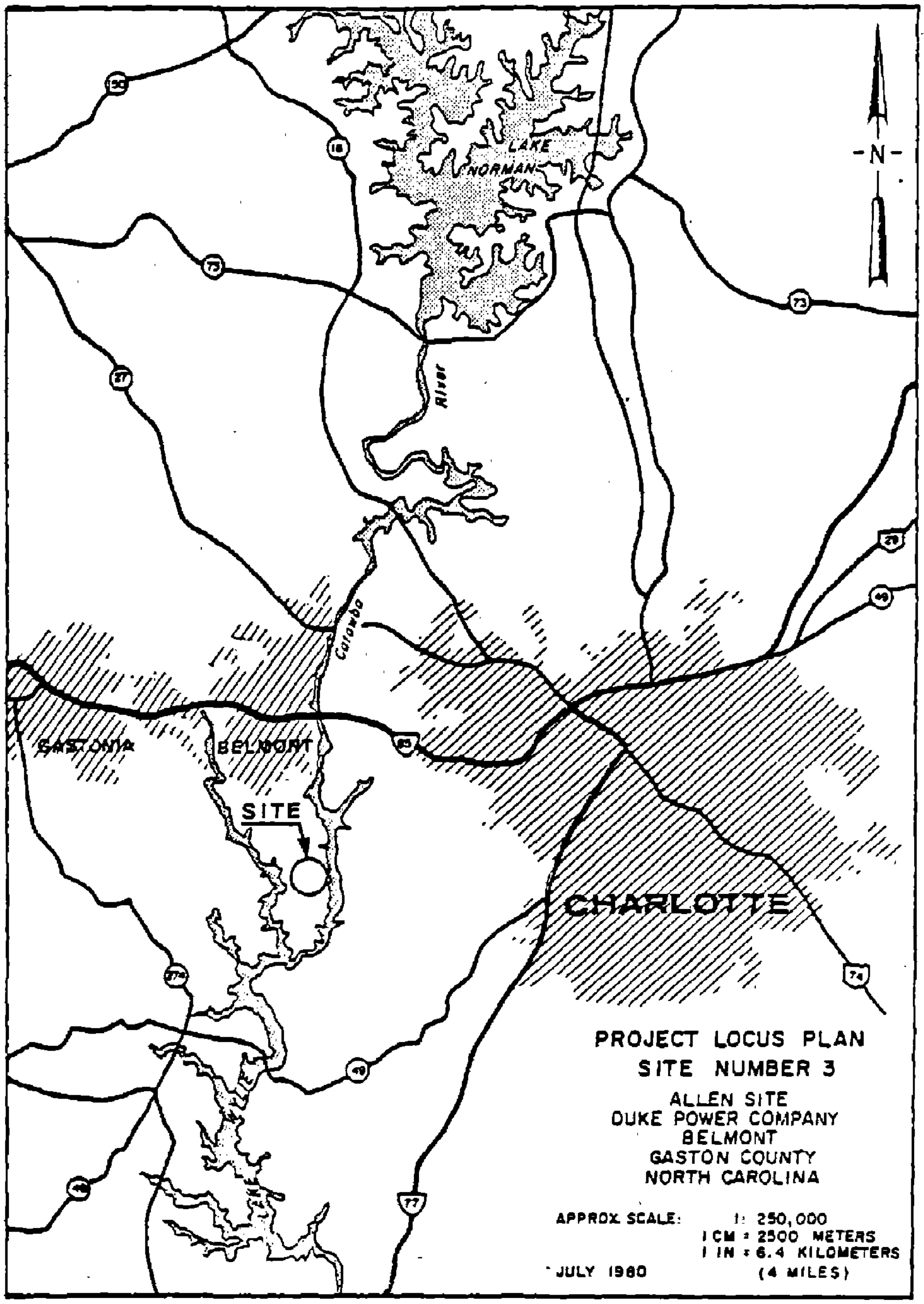

LAKE
NORMAN
River
Catawba
GASTONIA
BELMONT
SITE
CHARLOTTE
-N-
PROJECT LOCUS PLAN
SITE NUMBER 3
ALLEN SITE
DUKE POWER COMPANY
BELMONT
GASTON COUNTY
NORTH CAROLINA
APPROX. SCALE: 1: 250,000
1 CM = 2500 METERS
1 IN = 6.4 KILOMETERS
(4 MILES)
JULY 1980

FIGURE 5.1

Plant Allen and is widely practiced, with potentially broad applicability in the future.

5.2.1.2 Geologic Conditions--

The site area lies within the upland section of the Piedmont Physiographic Province and is characterized by broad, rolling topography and isolated Monadnock-type hills and ridges. The majority of the overburden soils were formed from the chemical decomposition of the underlying micaceous diorite bedrock. These deposits are referred to as residual soils and consist primarily of slightly plastic silts and sands with varying amounts of clay and quartz pebbles. The weathering profile is moderately deep but highly irregular. The bedrock and overburden soils are also characterized by a variety of younger, more permeable igneous dikes and sills which have intruded the original bedrock unit.

Active and ephemeral surface drainage systems have created several major surface drainage valleys with gradients lying at right angles to the Catawba River. Several small, localized alluvial deposits, filled with relatively loose and permeable material, are now incorporated within the ash basin complex.

Figure 5.2 summarizes the site area surficial geologic conditions, and Figure 5.3 presents an idealized subsurface geologic profile sketch.

5.2.1.3 Hydrologic Conditions--

The Plant Allen site lies within the Piedmont Groundwater Province. All groundwater is derived from local precipitation which varies from 1.12 to 1.38 m (44 to 55 in) annually, resulting in approximately 0.26 to 0.38 m (10-15 in) of percolation to the watertable. The plant obtains all of its cooling and process waters from Lake Wylie; approximately 50,000 m^3/day (14.4 million gal/day) are used for sluicing ash into the disposal pond, and ultimately return to Lake Wylie.

The original groundwater table depth varied considerably with the site topography, from at or above ground surface in the low-lying alluvial areas, to an approximate depth of 10 m (33 ft) beneath the higher elevations of the site. The limited data available indicate that plant discharges into the disposal ponds have created groundwater mounding in their immediate vicinity, saturating the former vadose zone above the regional piezometric level. All local surface and groundwater flow is easterly towards Lake Wylie (see Figure 5.2).

5.2.2 <u>Site Evaluation Plan and Site Development</u>

Duke Power Company conducted several environmental studies at Plant Allen that supplied valuable hydrogeologic baseline information; in addition, subsurface exploration information obtained in 1972 for the active ash pond dike construction was made available to the study team. Twenty existing observation wells installed throughout the plant site by Duke Power provided supplemental groundwater level monitoring locations.

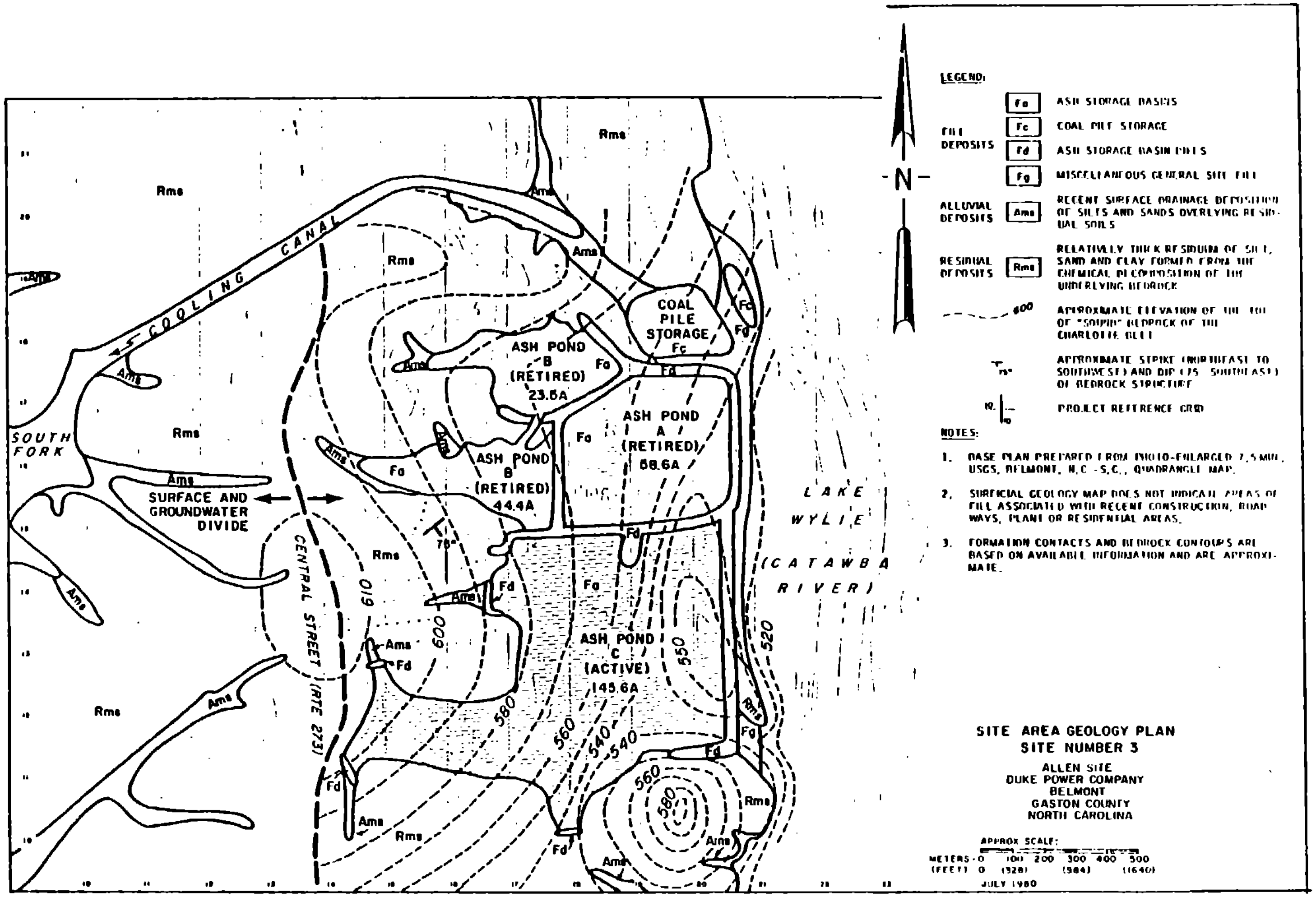

LEGEND:
FILL DEPOSITS
Fa ASH STORAGE BASINS
Fc COAL PILE STORAGE
Fd ASH STORAGE BASIN DIKES
Fg MISCELLANEOUS GENERAL SITE FILL
ALLUVIAL DEPOSITS
Ams RECENT SURFACE DRAINAGE DEPOSITION OF SILTS AND SANDS OVERLYING RESIDUAL SOILS
RESIDUAL DEPOSITS
Rms RELATIVELY THICK RESIDUUM OF SILT, SAND AND CLAY FORMED FROM THE CHEMICAL DECOMPOSITION OF THE UNDERLYING BEDROCK
600 APPROXIMATE ELEVATION OF THE TOP OF "SOUND" BEDROCK OF THE CHARLOTTE BELT
75° APPROXIMATE STRIKE (NORTHEAST TO SOUTHWEST) AND DIP (75° SOUTHEAST) OF BEDROCK STRUCTURE
PROJECT REFERENCE GRID
NOTES:
1. BASE PLAN PREPARED FROM PHOTO-ENLARGED 7.5 MIN. USGS, BELMONT, N.C.-S.C., QUADRANGLE MAP.
2. SURFICIAL GEOLOGY MAP DOES NOT INDICATE AREAS OF FILL ASSOCIATED WITH RECENT CONSTRUCTION, ROADWAYS, PLANT OR RESIDENTIAL AREAS.
3. FORMATION CONTACTS AND BEDROCK CONTOURS ARE BASED ON AVAILABLE INFORMATION AND ARE APPROXIMATE.
-N-
COOLING CANAL
SOUTH FORK
SURFACE AND GROUNDWATER DIVIDE
CENTRAL STREET (RTE 273)
ASH POND B (RETIRED) 23.5A
ASH POND B (RETIRED) 44.4A
ASH POND A (RETIRED) 58.6A
ASH POND C (ACTIVE) 145.6A
COAL PILE STORAGE
LAKE WYLIE (CATAWBA RIVER)
Rms
Ams
Fa
Fc
Fd
600
580
560
540
520
550
610
SITE AREA GEOLOGY PLAN
SITE NUMBER 3
ALLEN SITE
DUKE POWER COMPANY
BELMONT
GASTON COUNTY
NORTH CAROLINA
APPROX SCALE:
METERS 0 100 200 300 400 500
(FEET) 0 (328) (984) (1640)
JULY 1980

FIGURE 5.2

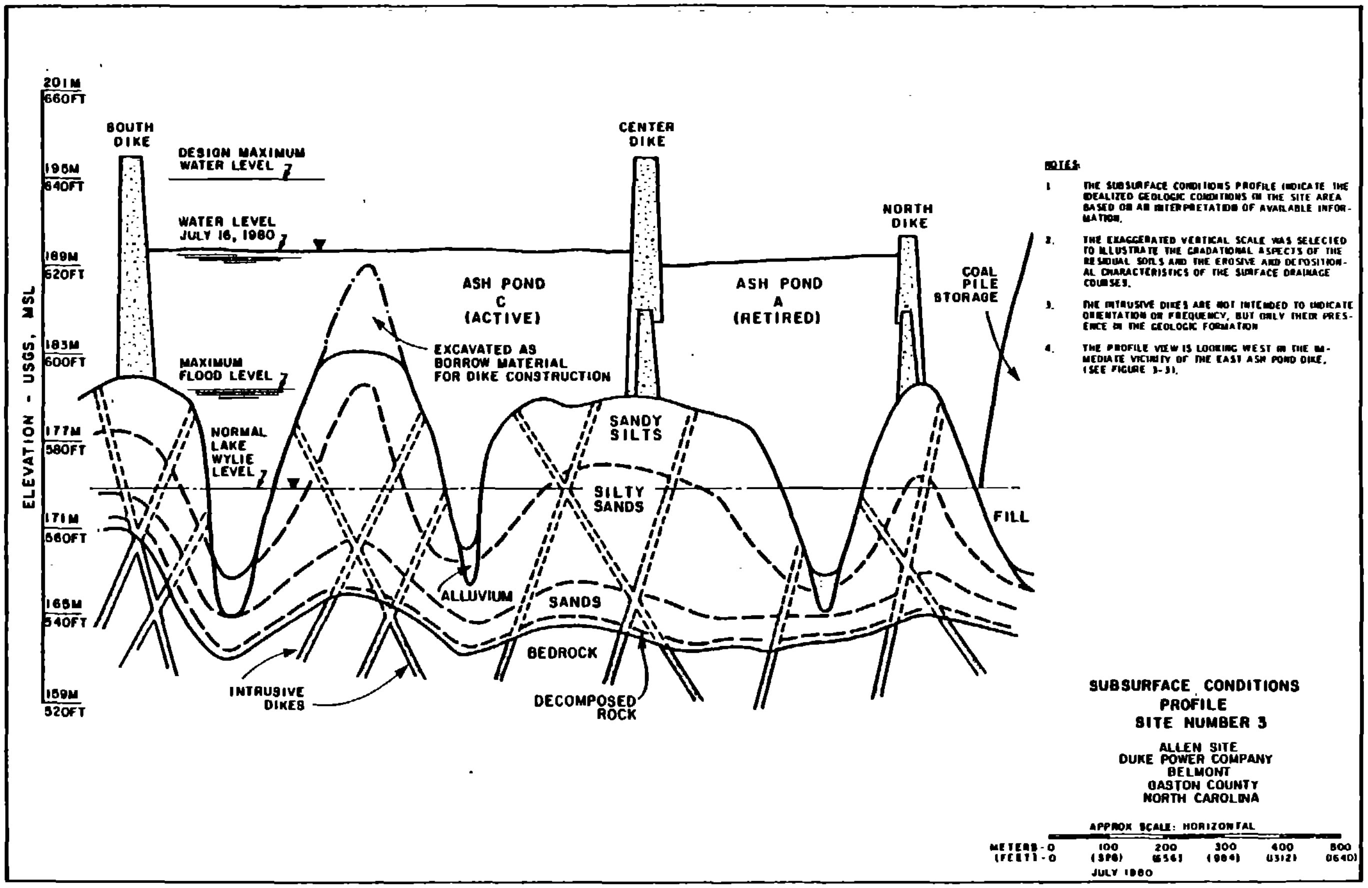

201M
660FT
195M
640FT
189M
620FT
183M
600FT
177M
580FT
171M
560FT
165M
540FT
159M
520FT
ELEVATION - USGS, MSL
SOUTH DIKE
DESIGN MAXIMUM WATER LEVEL
WATER LEVEL JULY 16, 1980
MAXIMUM FLOOD LEVEL
NORMAL LAKE WYLIE LEVEL
CENTER DIKE
ASH POND C (ACTIVE)
EXCAVATED AS BORROW MATERIAL FOR DIKE CONSTRUCTION
ASH POND A (RETIRED)
NORTH DIKE
COAL PILE STORAGE
SANDY SILTS
SILTY SANDS
FILL
ALLUVIUM
SANDS
BEDROCK
INTRUSIVE DIKES
DECOMPOSED ROCK
NOTES:
1. THE SUBSURFACE CONDITIONS PROFILE INDICATE THE IDEALIZED GEOLOGIC CONDITIONS IN THE SITE AREA BASED ON AN INTERPRETATION OF AVAILABLE INFORMATION.
2. THE EXAGGERATED VERTICAL SCALE WAS SELECTED TO ILLUSTRATE THE GRADATIONAL ASPECTS OF THE RESIDUAL SOILS AND THE EROSIVE AND DEPOSITIONAL CHARACTERISTICS OF THE SURFACE DRAINAGE COURSES.
3. THE INTRUSIVE DIKES ARE NOT INTENDED TO INDICATE ORIENTATION OR FREQUENCY, BUT ONLY THEIR PRESENCE IN THE GEOLOGIC FORMATION
4. THE PROFILE VIEW IS LOOKING WEST IN THE IMMEDIATE VICINITY OF THE EAST ASH POND DIKE. (SEE FIGURE 3-3).
SUBSURFACE CONDITIONS PROFILE
SITE NUMBER 3
ALLEN SITE
DUKE POWER COMPANY
BELMONT
GASTON COUNTY
NORTH CAROLINA
APPROX SCALE: HORIZONTAL
METERS-0 100 200 300 400 500
(FEET)-0 (328) (656) (984) (1312) (1640)
JULY 1980

FIGURE 5 3

The project site development plan for Plant Allen included the installation of multi-purpose wells and exploratory borings for hydrogeological and geotechnical evaluation purposes. Two upgradient observation wells were installed for background monitoring purposes, and seven downgradient wells were installed at various locations and elevations to determine the presence and vertical extent of any leachate movement. One well was installed in the retired ash disposal pond to determine the piezometric surface (which was in a state of hydrologic non-equilibrium), and two wells were installed within the active ash pond using floating equipment. A piezometer was also placed within the active ash disposal area for sampling purposes.

At the completion of installation of all monitoring apparatus in January 1981, the wells were flushed and bailed, and initial samples were obtained for chemical evaluation purposes.

The locations of all explorations and monitoring/sampling installations are indicated on Figure 5.4. A summary of all field tests and results, the types of samples collected, sampling locations, well types and well depths is presented in Table 5.1.

5.2.3 Physical Testing Results

Figure 5.5 shows the results of field and laboratory permeability tests performed on the fly ash and bottom ash wastes at the Allen site. In addition, results of standard penetration unified soil classification tests are presented.

One boring (3-1) was drilled in the abandoned ash pond that contains fly ash from mechanical collectors and from electrostatic precipitators and bottom ash. Apparently, ash has been discharged at various locations at the site resulting in the segregation of fly ash and bottom ash in Boring 3-1. It is estimated that the bottom ash, located near the center of the abandoned ash deposit, has a coefficient of permeability greater than or equal to 3×10^{-3} cm/sec. The fly ash located near the surface and near the bottom of the abandoned pond is much finer (87 percent of the particles passing a U.S. No. 200 sieve) with a coefficient of permeability ranging between 1×10^{-4} cm/sec and 1×10^{-5} cm/sec.

Two borings (3-2 and 3-3) were advanced through the active ash disposal pond that contains fly ash from both mechanical collectors and electrostatic precipitators as well as bottom ash, all of which have been disposed throughout the life of the active pond. Unlike the abandoned pond, the active pond had no distinct zones of fly ash and bottom ash. Instead, thin lenses of coarser ash were noticed throughout the ash deposit. Results of field permeability tests indicate a range in permeabilities of 2×10^{-4} to 4×10^{-3} cm/sec at those locations tested. Because of the horizontal layering of the ash in both ponds, it is estimated that the coefficient of permeability of the waste deposit in the vertical direction will be approximately the coefficient of permeability of the fly ash (approximately 1×10^{-4} cm/sec). The coefficient of permeability of the waste deposit in the horizontal direction

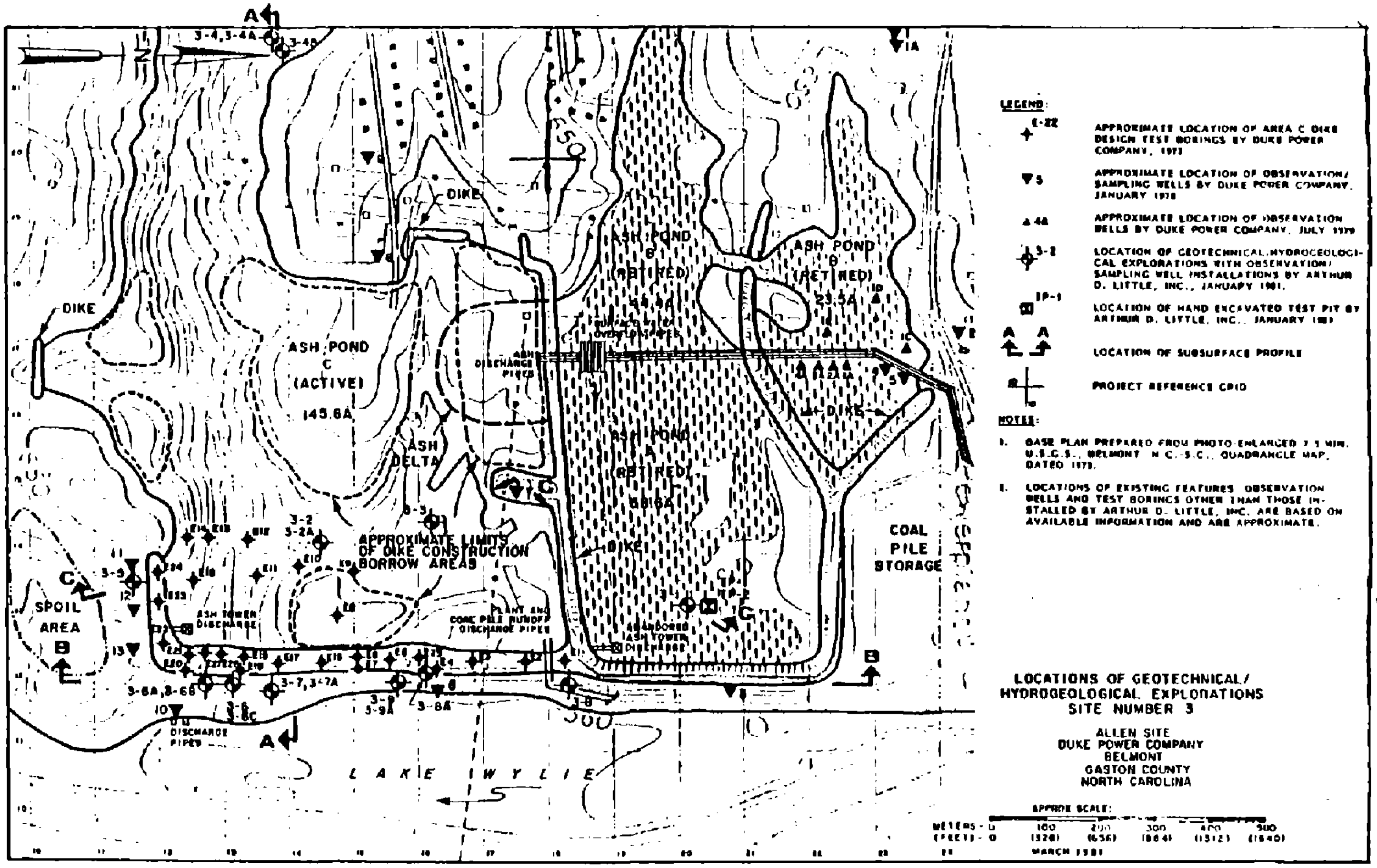

LEGEND:
E-22 APPROXIMATE LOCATION OF AREA C DIKE DESIGN TEST BORINGS BY DUKE POWER COMPANY, 1977
5 APPROXIMATE LOCATION OF OBSERVATION/SAMPLING WELLS BY DUKE POWER COMPANY, JANUARY 1978
4A APPROXIMATE LOCATION OF OBSERVATION WELLS BY DUKE POWER COMPANY, JULY 1979
3-2 LOCATION OF GEOTECHNICAL, HYDROGEOLOGICAL EXPLORATIONS WITH OBSERVATION/SAMPLING WELL INSTALLATIONS BY ARTHUR D. LITTLE, INC., JANUARY 1981.
TP-1 LOCATION OF HAND EXCAVATED TEST PIT BY ARTHUR D. LITTLE, INC., JANUARY 1981
LOCATION OF SUBSURFACE PROFILE
PROJECT REFERENCE GRID
NOTES:
1. BASE PLAN PREPARED FROM PHOTO-ENLARGED 7.5 MIN. U.S.G.S., BELMONT N.C.-S.C., QUADRANGLE MAP, DATED 1973.
2. LOCATIONS OF EXISTING FEATURES, OBSERVATION WELLS AND TEST BORINGS OTHER THAN THOSE INSTALLED BY ARTHUR D. LITTLE, INC. ARE BASED ON AVAILABLE INFORMATION AND ARE APPROXIMATE.
LOCATIONS OF GEOTECHNICAL/ HYDROGEOLOGICAL EXPLORATIONS SITE NUMBER 3
ALLEN SITE
DUKE POWER COMPANY
BELMONT
GASTON COUNTY
NORTH CAROLINA
APPROX SCALE:
METERS - 0 100 200 300 400 500
(FEET) - 0 (328) (656) (984) (1312) (1640)
MARCH 1981
ASH POND C (ACTIVE) 145.6A
ASH POND B (RETIRED)
ASH POND A (RETIRED)
ASH POND B (RETIRED) 23.5A
ASH DELTA
APPROXIMATE LIMITS OF DIKE CONSTRUCTION BORROW AREAS
DIKE
SPOIL AREA
COAL PILE STORAGE
ASH DISCHARGE PIPES
ASH TOWER DISCHARGE
PLANT AND COAL PILE RUNOFF DISCHARGE PIPES
ABANDONED ASH TOWER DISCHARGE
DISCHARGE PIPES
LAKE WYLIE
3-4,3-4A
3-4B
3-2
3-2A
3-3
3-5
3-6A,3-6B
3-6
3-6C
3-7,3-7A
3-9
3-9A
3-8A
3-8
3-1
TP-2
1A
A
B
C

FIGURE 5.4

TABLE 5.1

SITE DEVELOPMENT SUMMARY

SITE: PLANT ALLEN SITE
GASTON COUNTY, NORTH CAROLINA

DATES: January 6, 1981 - January 28, 1981
FILE NO. 453503

TOTAL NO. EXPLORATIONS ON SITE: 9

Boring #	3-1	3-2	3-3	3-4
Soils Classification [depth (m); class]	0-17.4; Fly Ash 17.4-18.4; Alluvium 18.4-18.7; Weathered Rock	0-12.3; Fly Ash 12.3-13.6; Alluvium 13.6-14.3; Residual Soils	0-7.5; Fly Ash 7.5-8.5; Alluvium 8.5-11.4; Residual Soil	0-3.3; Fill 3.3-6.2; Alluvium 6.2-6.9; Weathered Rock
Number of Samples Obtained	20	23	16	12
Field Permeability Test [depth (m); Results (m/sec)]		13.3-14.5; 3×10^{-7} 3-2 7.6-8.8; 4×10^{-6} 3-2A	9.8-11.4; 2×10^{-7} 1.2-3.2; 3.1×10^{-6} to 11.0' - 16.0'	3.4-5.8; 2.7×10^{-7}
Well Installation [wellpoint type; diameter (in); location (m)]	0.020" slot; 2.0 ID 17.1-18.3	Vyon fabric; 1.0 ID 3-2 13.3-14.5 7.6-8.8 3-2A	Vyon fabric; 1.0 ID 9.9-11.1	0.020" slot; 2.0 ID 3-4 3.4-4.9 0.020" slot; 2.0 ID 3-4A 1.4-2.9

Boring #	3-4B	3-5	3-6	3-6A,C
Soils Classification [depth (m); class]	0-1.7; Fill 1.7-3.0; Alluvium 3.0-6.2; Rock	0-0.9; Fill 0.9-14.3; Weathered Rock	0-9.8; Fill 9.8-10.8 Alluvium 10.8-18.1; Decomposed Rock	0-9.8; Fill 3-6A 9.8-11.0; Alluvium 0-12.3; Residuals 3-6C 12.3-13.0; Rock
Number of Samples Obtained	6	13	24	4
Field Permeability Tests [depth (m); results (M/sec)]	4.1-5.0; 4.0×10^{-6} m/s	10.1-13.2; 10×10^{-6} m/s	No Test in Piezometer	10.1-11.0; 1.5×10^{-6} m/s 3-6 3.1-6.1; 6.0×10^{-7} to 5.2×10^{-7} m/s 3-6B
Well Installation [Well point type; diameter (in); location (m)]	0.020" slot; 2.0 ID; 4.1-5.6	0.020" slot; 2.0 ID; 10.1-13.2	Vyon fabric; 1.0 ID; 11.1-13.0	0.020" slot; 2.0 ID 6A 10.1-10.7 0.020" slot; 2.0 ID 6B 3.8-5.3 Vyon fabric; ID 6C 10.8-12.9

(continued)

TABLE 5.1

Boring #	3-7, 7A		3-8, 8A		3-9	3-9A
Soils Classification [depth (m); class]	0.6.2; Residual Soil 6.2-8.0; Quartzite		0-4.0; Fill 4.0-10.7; Weathered Rock		0-3.4; Fill 3.4-5.2; Weathered Rock	0-3.4; Fill 3.4-4.3; Alluvium 4.3-9.9; Weathered Rock
Number of Samples Obtained	9		11		6	5
Field Permeability Tests [depth (m); Results (M/sec)]	6.1-7.6; 4.6 x 10^{-5} 2.6-4.1; 3.7 x 10^{-6}	3-8 3-8A	9.1-10.7; 4.7 x 10^{-6} 2.6-4.1; 3.7 x 10^{-6}	3-8 3-8A	3.7-4.4: 1.0 x 10^{-5}	7.5-9.0; 4.1 x 10^{-6} m/s
Well Installation [well point type; diameter (in);	0.020" slot; ID; 6.1-7.6 Vyon fabric: 1.0 ID:	7	0.020" slot; 2.0 ID; 9.1-10.7 0.020' slot: 2.0 ID:	3-8	0.020"; 2.0 ID; 3.7-4.4	0.020 slot; 2.0 ID; 7.5-9.0

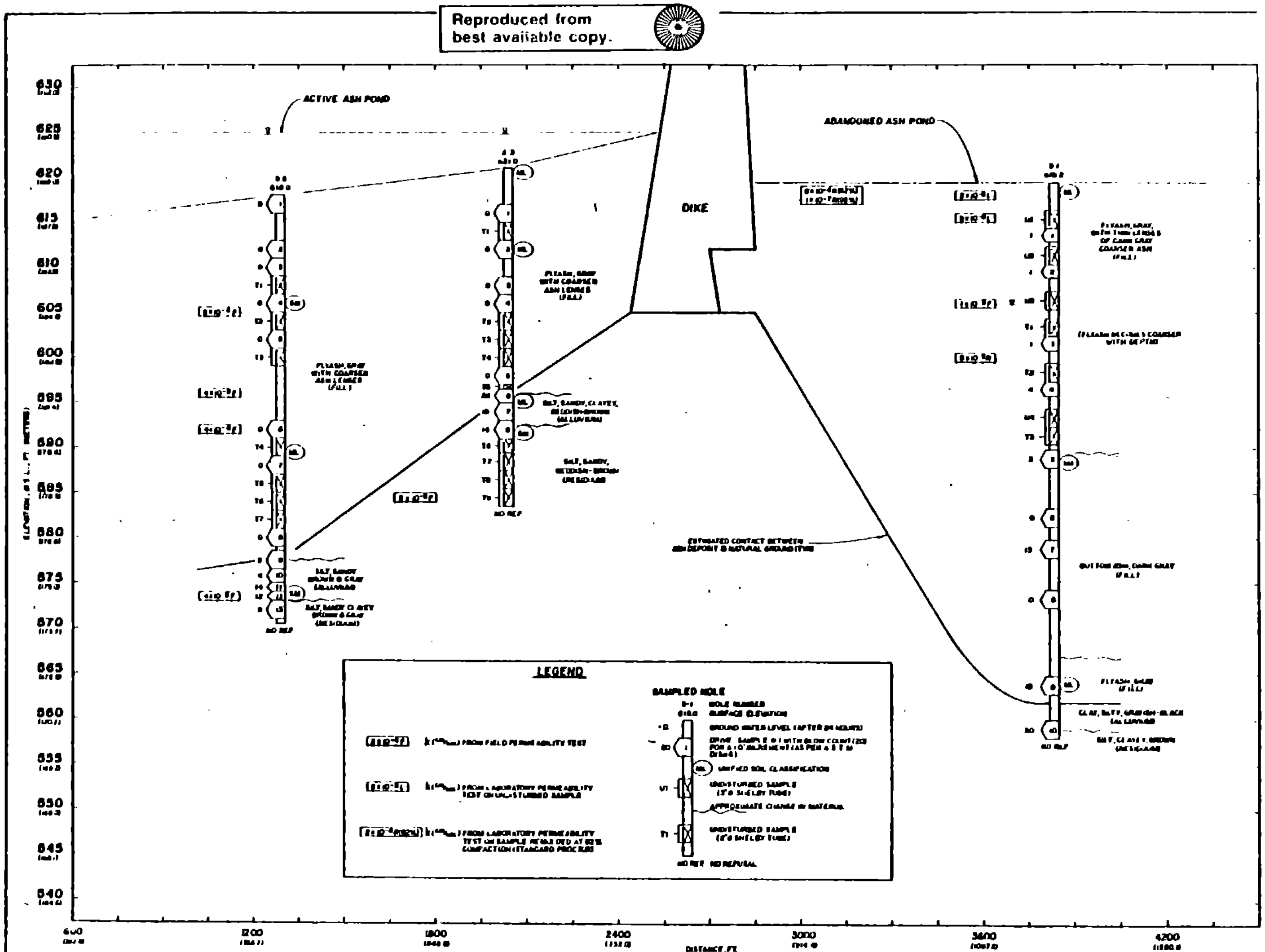


FIGURE 5.5 GEOTECHNICAL EVALUATION RESULTS, ALLEN PLANT, DUKE POWER CO., GASTON COUNTY, N.C.

is approximately equal to the coefficient of permeability of the coarser ash lenses (approximately 3 x 10^{-3} cm/sec).

A more detailed presentation of the physical testing results for Plant Allen wastes is provided in Appendix E. Table 5.2 provides a summary of selected physical testing results.

5.2.4 Chemical Testing Results

The site monitoring infrastructure was developed in January 1981, with emphasis on the active ash pond. At that time, samples of wastes and soils were collected for physical and chemical testing; surface water and groundwater samples were obtained for chemical testing. Subsequent water sampling occurred in late February through early March 1981 and in July 1982. Year-to-date precipitation was somewhat below normal prior to the 1981 visits, but it was in the high to normal range prior to the 1982 visit. Boiler cleaning wastes were collected for analysis in November and December 1981.

Selected results of chemical analyses of samples from the Allen site are presented in Table 5.3. A summary of chemical attenuation test results is presented in Table 5.4. A compilation of the chemical analysis results is presented in Appendix F.

5.2.5 Environmental Assessment

5.2.5.1 Approach for Plant Allen--

The environmental assessment of the Allen site results focused on the following three issues:

1) effects of the ash pond leachate on downgradient groundwater quality;

2) effects of the ash pond leachate on water quality in Lake Wylie, including comparison with the magnitude of ash pond point source (overflow) discharge; and

3) effects of co-disposal of intermittent, metal-rich waste streams (especially boiler cleaning wastes) on Items 1 and 2 above.

The steps employed in the environmental assessment at this site were as follows:

- A site subsurface geological profile and a site water balance were prepared.

- The values of and trends in chemical sampling and analysis results for the various areas of the site were compared with the results of previous sampling by Duke Power Company and with relevant EPA standards for groundwater protection.

TABLE 5.2

SELECTED PHYSICAL TESTING RESULTS

ALLEN PLANT[a]

Permeability (cm/sec)	$1 \times 10^{-7} - 2 \times 10^{-4}$
Specific Gravity	1.96 - 2.20
Grain Size Distribution (Weight Percent)	
• > 74 µm	13 - 69
• 2 - 74 µm	22 - 85
• < 2 µm	0 - 15
Moisture Content (Weight Percent)	10.9 - saturated
Effective Strength Parameters	
• Angle of Internal Friction	28.8°
• Effective Cohesion (PA;psi)	0.0; 0.0

[a]See Appendix E for more detailed data.

Source: Arthur D. Little, Inc., and Bowser-Morner Testing Laboratories, Inc.

TABLE 5.3

SELECTED DATA FOR REPRESENTATIVE SAMPLING LOCATIONS
AT ALLEN PLANT

CONCENTRATION (mg/ℓ or ppm except where noted)

LOCATIONS	SO_4	Ca	B	Sr	As(ug/ℓ)
Well 3-4B (Background)	2.1	9.95-10.9	<0.005-0.016	0.141-0.166	<0.2-7.0
Well 3-1 (Under Retired Pond)	89.9-100	59.4-64.1	1.71-1.87	3.60-4.71	56.3-57.2
Well 3-2A (In Active Ash Pond)	169.4-320	63.7-129	1.99-3.68	1.35-4.13	318-2425
Well 3-2 (Under Active Ash Pond)	1.4	15.8-17	0.057-0.76	0.241-0.274	<0.15-1.6
Wells 3-7A and 3-8 (Downgradient)	13-76.2	18.1-37.9	0.05-0.999	0.231-0.411	<0.10-0.78
Wells 3-6 and 3-9 (Downgradient)	4-5.4	11.2-18.0	<0.005-0.116	0.078-0.164	<0.2
Pond Overflow 3-13	56-62	19.6-21.4	0.205-0.238	0.297-0.342	58
Ash Solids 3-2 and 3-3	--	2251-4578	--	112-239	16.2-57.1
Background Soils 3-4	--	471-4056	--	8.85-33.1	0.6-1.41

EPA Interim Primary Drinking Water Standards for As - 50 ug/ℓ
EPA Proposed Secondary Drinking Water Standards are: Cu - 1 mg/ℓ
SO_4 - 250 mg/ℓ
Zn - 5 mg/ℓ
Fe - 0.3 mg/ℓ
Mn - 0.05 mg/ℓ
EPA Criterion for Protection of Sensitive Crops: B - 0.750 mg/ℓ

continued

TABLE 5.3

CONCENTRATION (mg/ℓ or ppm except where noted)

LOCATIONS	Cu	Ni	Zn	V	Fe	Mn
Well 3-4B (Background)	<0.008	<0.05	<0.05	<0.005-0.016	<0.01	<0.01-0.07
Well 3-1 (Under Retired Pond)	<0.008	<0.05	<0.05	0.018-0.034	<0.01	<0.01
Well 3-2A (In Active Ash Pond)	<0.008	<0.05	<0.05	0.035-0.043	<0.01-0.02	0.06-0.16
Well 3-2 (Under Active Ash Pond)	<0.008	<0.05	<0.05	<0.005	25.9	6.44-14
Wells 3-7A and 3-8 (Downgradient)	<0.005-0.013	<0.05	<0.05	<0.006	<0.01-0.02	<0.01-0.07
Wells 3-6 and 3-9 (Downgradient)	<0.008	<0.05	<0.05	<0.005-0.014	0.01-14.4	<0.01-2.72
Pond Overflow 3-13	<0.008	<0.05	<0.05	0.030-0.047	<0.01	<0.01-0.09
Ash Solids 3-2 and 3-3	20.8-45.1	15.3-26.0	18.5-45.7	22.2-41.5	11,700-29,491	83-171
Background Soils 3-4	9.52-17.6	4.48-10.8	22.8-36.2	28.1-49.1	11,164-16,558	155-303

EPA Interim Primary Drinking Water Standards for As - 50 ug/ℓ
EPA Proposed Secondary Drinking Water Standards are: Cu - 1 mg/ℓ
SO_4 - 250 mg/ℓ
Zn - 5 mg/ℓ
Fe - 0.3 mg/ℓ
Mn - 0.05 mg/ℓ
EPA Criterion for Protection of Sensitive Crops: B - 0.750 mg/ℓ

TABLE 5.4

SELECTED RESULTS OF SOIL ATTENUATION STUDIES
ALLEN SITE[a]

Element and Soil Sample[a]		Solution Concentration (ppb)	Soil Capacity (μg/gm)	Soil Capacity ÷ Solution Concentration
Arsenic	(A)	<0.2-413	1.0-215	>5500-261
	(B)	<0.2-225	0.3-47	>5500-128
	(C)	2.4-492	1.1-66.9	458-136
Selenium	(A)	0.2-113	0.25-127	90-9844
	(B)	<0.1-96	0.25-124	2500-92
	(C)	2.8-138	0.24-1.73	86-5.1
Calcium	(A)	42.3-73 mg/ℓ	68-590	1.6-8.1
	(B)	12.4-368 mg/ℓ	130-322	0.5-10
	(C)	52.5 mg/ℓ	44 ± 5	0.8
Cadmium	(A)	40-120	0.24-42	6-350
	(C)	70-150	0.17-12	2.4-8.0
Chromium	(A)	0.040-0.190	0.03-0.96	<0.35-11.8
	(B)	0.040-0.130	0.47-1.45	11.8
	(C)	0.030-0.250	0.06-0.49	<0.35-16.3
Copper	(A)	<0.008-0.072	>0.03-328	12-4500
	(B)	0.012-0.159	0.14-290	8.3-1800
	(C)	0.013-0.179	0.69-220	15-1200
Nickel	(B)	0.210	4.5 ± 1.3	---
	(C)	0.220	0.31	1.4
Vanadium	(A)	0.009-0.030	0.05-6	5.5-200
	(B)	0.008-0.014	0.05-2.20	6-157
	(C)	0.021-0.031	0.03-0.05	1.4-1.6

[a]Soil types used were as follows: (A) boring 3-2, alluvial material, ~30% clay; (B) boring 3-3, residual soil, silty sand; and (C) boring 3-6, alluvial material, ~20% clay.

- Using the chemical analysis results and the gross and net water balance, mass balance estimates were made for selected contaminants entering the ash pond via the fly ash and bottom ash discharges and through the addition of boiling cleaning wastes, and for contaminants <u>leaving</u> the pond via overflow to Lake Wylie and leaching to groundwater.

- The water balance, geological profile, and chemical and physical testing results were considered together to structure and evaluate hypotheses concerning the nature of leachate generation and movement at the site. The importance of events such as the temporary cessation of the point source (pond overflow) discharge during boiler cleaning was considered in this step.

- To evaluate further hypotheses concerning chemical attenuation of leached trace metals by the soils surrounding the ash pond, a series of attenuation tests were executed using ash pond liquor and local soils.

- The results of the attenuation tests were evaluated along with the water balance, geological profile, mass balance and physical testing data to estimate the potential for long-term leaching of arsenic from the ash ponds to Lake Wylie.

- The broader implications of the Allen site results were considered in terms of their applicability to similar combinations of waste types, disposal methods and environmental settings. This step can be considered particularly important for the Allen site because the combination represented there is quite prevalent at other sites.

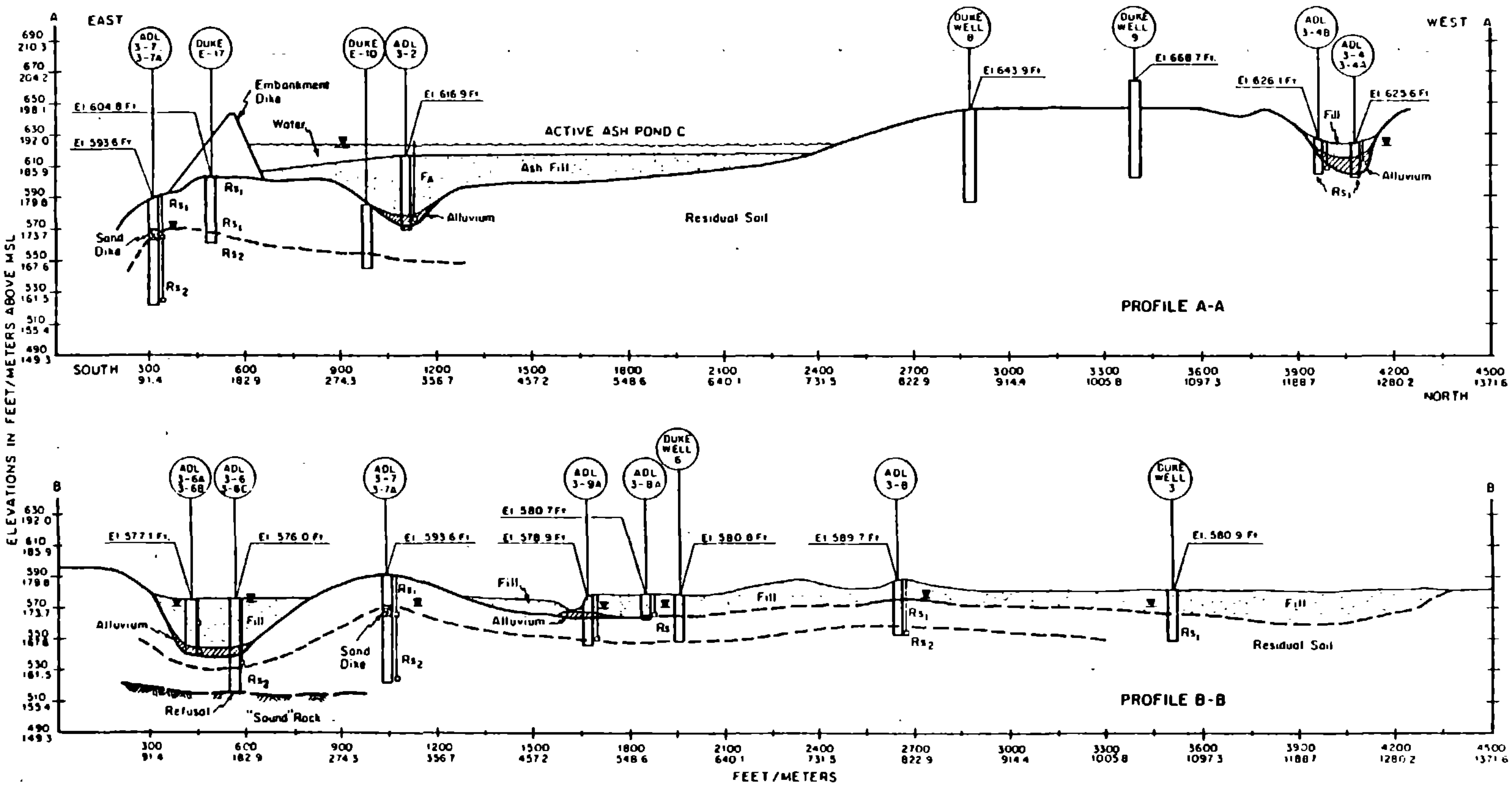
5.2.5.2 Geological Profile and Water Balance--

Figure 5.6 illustrates the subsurface geological profiles for three areas of the Allen waste disposal site as delineated above in Figure 5.4. These profiles were prepared on the basis of the site development results for this program along with the available site background information.

The annual water balance estimated for the Allen site is summarized briefly below and illustrated in Figure 5.7.

<u>Definition of Terms</u>

P = Precipitation
Ev = Evaporation
I_{PS} = Point Source Input to Pond
O_{PS} = Point Source Output from Pond
R_{SW} = Surface Water Runoff into Pond
R_{GW} = Groundwater Runoff beneath Pond
G_F = Groundwater Movement through Fill
G_A = Groundwater Movement through Alluvium
G_R = Groundwater Movement through Residual Soil

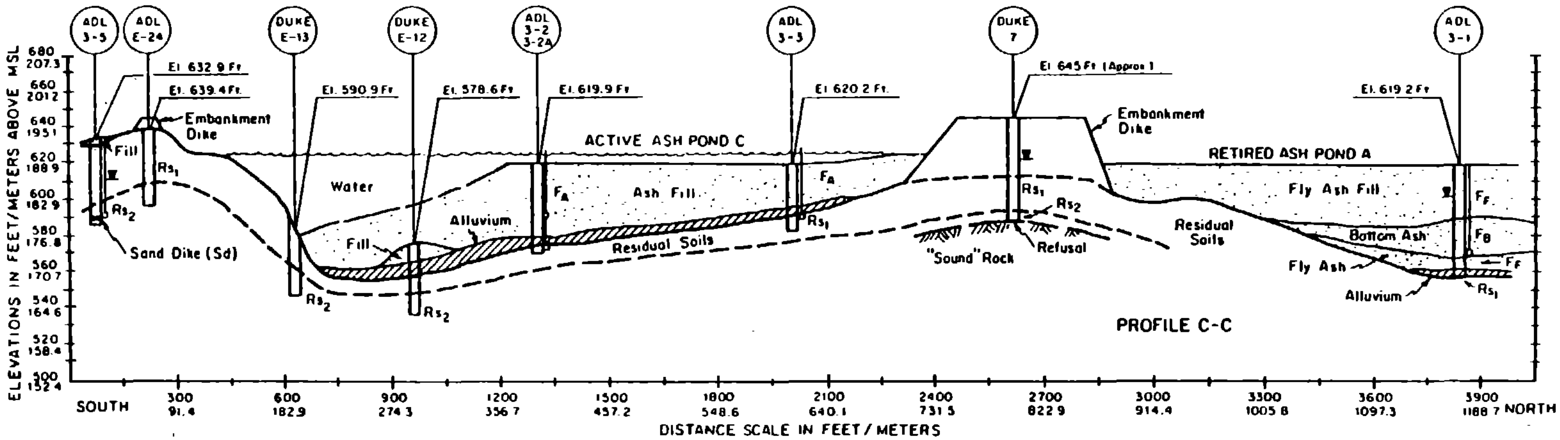


SUBSURFACE GEOLOGICAL PROFILES - ALLEN SITE

DUKE POWER COMPANY, GASTON COUNTY, N.Y.

FIGURE 5.6

(continued)



LEGEND

Alluvium A – Recent stream alluvial deposits varying from loose silty fine sands to soft, very slightly organic clayey silts with trace amounts of organic matter, overlying residual soils.

Residual Soils

- Rs – Generally fine grained, cohesive soils formed from the chemical decomposition of the bedrock. General increase in grain size and density with increasing depth
- Rs_1 – Soft to stiff, reddish brown to gray-white clayey silt to silt, little clay with trace sand, mica & occasional gravel
- Rs_2 – Medium compact to compact, yellow brown to greenish brown silt to fine sandy silt with trace amounts of clay, mica and gravel (gravel content increases with depth).

Sand Dikes (Sd) – Younger intrusive igneous dikes varying in thickness from a few centimeters (inches) to several meters (feet) have intruded the overall older bedrock unit. Many of those dikes were observed in surface exposures and were encountered in several test borings. The dikes have decomposed to a coarse sand and gravel.

"Sound" Rock – In test borings, where abrupt auger penetration "refusal" was encountered at depths, it is assumed to be the top of the relatively unweathered, sound, competent bedrock.

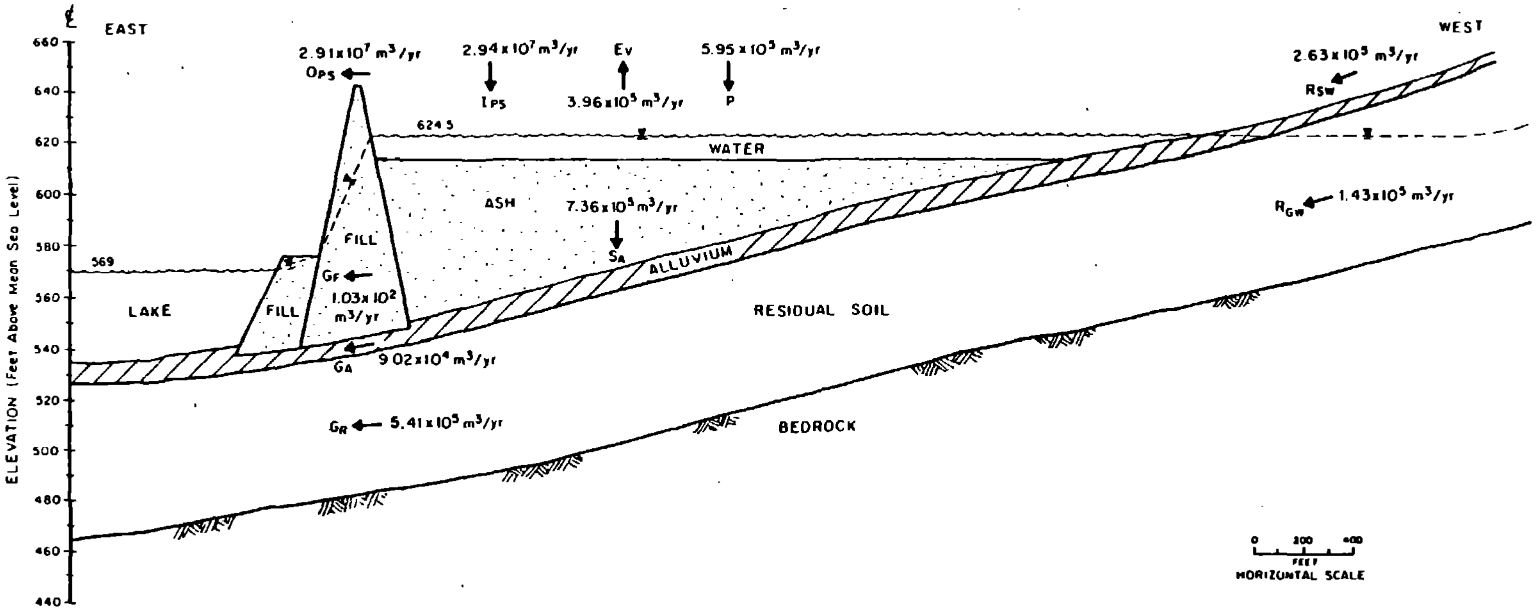
Fills – Relatively recent overburden materials associated with construction of the ash pond disposal facility or disposed ash.

- F – General excess site construction fill materials utilized in increasing available land area downgradient of the disposal facility. Occasional fill materials were encountered which predated the disposal construction. Reddish brown to dark brown clayey silts to fine sandy silts with varying amounts of mica, sand, gravel and organic matter.
- F_A – Miscellaneous, very loose to very soft, dark gray to black, intermixed ash fill with occasional stiff leaves and layers, undifferentiated from Bottom Ash and Fly Ash.
- F_B – Very loose to very soft, black, coarse grained bottom ash fill.
- F_F – Very loose to very soft, gray, fine grained fly ash fill with occasional stiff layers and leases.
- Symbol representing water depth in completed borehole or groundwater monitoring well at time of installation
- Symbol representing location of installed groundwater monitoring well or piezometer.

SUBSURFACE GEOLOGICAL PROFILE – ALLEN SITE

DUKE POWER COMPANY, GASTON COUNTY, N.C.

FIGURE 5.6



Refer to text for definition of terms

PLANT ALLEN WATER BALANCE (Annual Basis)

FIGURE 5.7

S_A = Water Seepage through Bottom of Pond

Calculation of O_{PS}

Inflow to Pond = Outflow from Pond

$$P + R_{SW} + I_{PS} = Ev + S_A + G_F + O_{PS}$$

$$O_{PS} = [5.95 \times 10^5 + 2.63 \times 10^5 + 2.94 \times 10^7 - 7.36 \times 10^5 - 1.03 \times 10^2]\ m^3/yr$$

$$O_{PS} = 2.91 \times 10^7\ m^3/yr$$

Balance of Groundwater Flow

Groundwater Inflow = Groundwater Outflow

$$R_{GW} + S_A = G_A + G_R$$

$$1.43 \times 10^5\ m^3/yr + 7.36 \times 10^5\ m^3/yr = 9.02 \times 10^4\ m^3/yr + 5.42 \times 10^5\ m^3/yr$$

$$8.79 \times 10^5\ m^3/yr \cong 6.31 \times 10^5\ m^3/yr$$

5.2.5.3 Evaluation of Testing Results--

The results of chemical analyses of samples, in conjunction with available background data, indicate the following:

- Absolute and relative concentration values measured on different dates at the same sampling locations were similar.
- Concentrations of likely ash-related "tracers" (boron, sulfate, calcium, strontium, vanadium and arsenic) were significantly higher in groundwater obtained from wells placed within the ash than in water from the other wells at the site; with the exception of vanadium, concentrations were significantly higher in the ash solids than in background soils (see Table 5.3).
- Concentrations of these same "tracers" exhibited a generally consistent pattern in downgradient wells, as follows:
  - Elevations of concentrations versus background concentrations were evident at some of the downgradient wells (wells 3-7A and 3-8, Figure 5.4);
  - Elevations of concentrations versus background concentrations were slight or lacking in samples from the other downgradient wells (e.g., wells 3-2, 3-6 and 3-9, Figure 5.4); and
  - High levels of iron and manganese in background soils (approximately 17,500 ppm and 400 ppm, respectively), groundwaters

(0.01 to 16 ppm and 0.014 to 11 ppm, respectively), and the River/Lake upgradient and upstream of the site (0.100 to 2.5 mg/l and up to 0.050 mg/l, respectively) were measured in this program and/or previous studies.

- Arsenic was measured at significantly elevated concentrations in groundwaters from lower strata within the ash (over 1000 µg/l at 12 to 14 m (38 to 40 ft); 50 to 100 µg/l in higher strata). The results of the EPA Extraction Procedure (EP) on samples from this site indicated arsenic levels about two orders of magnitude lower than the in situ field values (see Table 5.3). As noted above, arsenic was measured at near background levels in downgradient wells.

- Attenuation tests with ash pond liquor and site soils (see Table 5.4) indicated that the local soil attenuation capacity for arsenic was at least 10 µg/g soil; the attenuation capacity of the site soils was generally greater for the various trace metals than that measured for soils at any of the other five sites in the program.

- The amounts of copper, nickel, and zinc added to the pond during a boiler cleaning event represent 3 to 22 percent (280 kg, 71 kg and 80 kg, respectively) of the total amount of these same elements added in ash sluice water plus ash solids over a period of 18 months (time between boiler cleaning events). Other constituents added by boiler cleaning represented less than two percent of the total amount added over 18 months, and the contributions of most were less than 0.1 percent of the total amount added to the pond.

- The chemical analysis results of all sampling trips showed copper, nickel and zinc concentrations in well water, pond toe drains and pond overflow to be consistently low, approximately at or below the applicable detection limits. These were also generally at comparable levels in the ash and background soils, (Copper was somewhat elevated in the ash, as shown in Table 5.3).

- Natural soils under the site, treated with partial extraction, did not show much difference in concentrations of these three elements (Copper: 11-19 ppm; Nickel: 5-6 ppm; Zinc: 21-35 ppm) from similar background soils.

5.2.5.4 Cause and Effect Relationships--

The results from the investigations at Plant Allen are consistent with the following hypotheses:

- Leachate generated within the ash ponds contains elevated concentrations of several waste-related components. The surrounding soils in the immediate vicinity of the ponds have thus far been able to attenuate significant fractions of such leachate contaminants as arsenic and vanadium.

- Leachate water from the upgradient (western) portions of the ash ponds has not yet moved sufficiently to create steady-state concentrations of unattenuated parameters at the downgradient wells. This applies particularly to the active pond, but also appears to apply, to a lesser degree, to the most recently deactivated pond.

- Based on the results of the attenuation tests (Table 5.4) and analyses of site wastes and soils (Table 5.3), it appears likely that arsenic is chemically attenuated by iron and/or manganese in the soils under and around the ash ponds. Combining this information with the available information on arsenic inputs to the pond, the water balance and supporting hydrogeologic data, it also appears that the attenuative capacity of the surrounding soils would be sufficient to prevent passage of arsenic leachate with concentrations in exceedance of drinking water standards into Lake Wylie for longer than the estimated 15 year operating life of the active pond. This estimate would apply even if the pond remained active for almost 100 years, and for considerably longer (in excess of 500 years) if the pond is retired as scheduled.

- The chemical nature of various boiler cleaning wastes and the ash pond liquor (into which the former is periodically added) are such that chemical interactions likely alter the distribution of elements between the liquid and solid states. For example, while copper represents the most significant element added with boiler cleaning (by percent increment), precipitation of copper may occur upon decrease of the cleaning waste ammonia concentration by dilution in the pond. Copper and other elements, such as nickel or zinc, could be precipitated by additional interactions between boiler cleaning wastes and ash pond liquors. Such hypotheses are supported strongly by the lack of concentration elevation (availability) of these elements in pond liquor, the pond discharge well water and soil samples under the site (see Table 5.3).

Selected aspects of the above hypotheses are discussed further below.

Geohydrologic conditions at the site and the site water balance (Figures 5.6 and 5.7) reflect the fact that the spatial distribution of subsurface materials is relatively complex, leading to great uncertainties in defining leachate movement and admixing patterns. However, several pieces of information suggest that the downgradient wells have not yet reached steady state conditions with respect to the movement and admixing of leachate generated by the pond.

The water balance calculations suggest that downward leachate flow driven by the head of standing water in the pond is an important flow feature in the alluvial deposits under part of the pond. There is no analogous data to define vertical flow velocities in the residual soils that underlie most of the pond, which are estimated to carry the bulk of water flowing downgradient of the pond.

Given the variations and uncertainty in the length of flow paths, hydraulic gradient (especially accounting for variations over the life of the facility) and hydraulic conductivity at this site, it is only possible to conclude that leachate generated in eastern portions of the pond has begun to reach the downgradient well locations. It is not clear whether leachate from western portions of the pond has yet reached to downgradient locations, or what fraction of the total leachate emanating from the pond has actually migrated toward or reached the downgradient wells. Since steady state conditions would not be achieved until the whole pond (all potential flow paths carrying leachate) contributes leachate to downgradient locations, it is plausible that steady state conditions have not been achieved.

Another element of the water balance (see Section 5.2.5.2) also suggests that steady state conditions have not been achieved. Again, the magnitude of geohydrologic uncertainty compromises the conclusion. The water balance indicates that leachate seepage from the base of the pond exceeds groundwater underflow from upgradient areas by roughly an order of magnitude. The estimated seepage rate also exceeds the estimated groundwater flow rate away from the site by roughly a factor of two. This discrepancy probably roughly indicates the magnitude of error associated with the seepage rate estimate, but may be partly associated with the fact that water movement patterns at the site are still dynamically responding to pond seepage. (Seepage from all parts of the pond bottom has not yet reached downgradient locations.) At face value, the water balance estimates suggest that at steady state nearly all the downgradient flow would be leachate. Even if the seepage rate is one half of the estimated value, downgradient water at steady state would still be roughly 80 percent leachate plus 20 percent underflowing groundwater. Observed concentration levels for major constituents indicate that downgradient wells are sampling a mixture of roughly 20 percent leachate plus 80 percent underflowing groundwater. Thus, allowing for reasonable levels of uncertainty in the water balance, it appears that downgradient locations have not reached steady state, and increasing concentrations over the next several years would be expected.

Available data, however, cannot support a precise estimate of future groundwater quality at the site, although it is clear that steady state concentrations may range between existing concentrations and concentrations typical of ash leachate (e.g., as in well 3-2A at present).

5.2.5.5 Environmental Effects Implications--

Existing levels of most constituents in almost all groundwater sampling locations at the site do not exceed present water quality standards (see Table 5.3). The exceptions include:

- iron and manganese, which exceed secondary drinking water standards in background waters and over most of the site. (It has been noted that these elements may aid in attenuating constituents such as arsenic.); and

- sulfate, arsenic and boron in the "in-waste" well, with the concentrations of the latter two also high in groundwater under the waste, and in some cases, in the pond overflow.

As illustrated by the definition of water balance given in Section 5.2.5.2, the potential incremental leachate impacts at this site can be put in perspective by comparison with the point source discharge from the ash pond. Considering the mass transport rates of selected constituents from the Plant Allen pond, the following conclusions may be readily drawn:

- leachate generation rates are typically one to two orders of magnitude less than point source discharge rates;
- present downgradient transport of leachate into Lake Wylie appears to be about 8 times less than leachate generation rates; and
- the mass of ash-related contaminants entering Lake Wylie by non-point source transport appears to be about two orders of magnitude less than the mass entering by point source discharge.

The reasons why downgradient transport rates appear to be less than leachate generation rates have been discussed earlier, but are summarized as follows:

- downgradient locations may not be at steady state;
- some constituents have been attenuated; and
- leachate generation rates may be overestimated.

Exceptions to the above conclusions may be noted for iron and manganese, whose presence at greater concentrations in background water dominates the leachate contribution.

Considering the maximum observed concentrations of non-attenuated species (e.g., sulfate) in the leachate and the dominant influence of the point source discharge, the long-term impacts of leachate migration to Lake Wylie at this site are expected to be insignificant.

The results from the Allen site support conclusions 1,2,3, and 5 in Section 5.1 and have the following broader implications for similar disposal practices:

1. Concentrations of at least one trace metal (arsenic) in coal ash leachate can significantly exceed the applicable drinking water standards, and can be present at orders of magnitude higher in situ concentrations than would be indicated by the results of the EP test.
2. Chemical attenuation of leachate trace metals by surrounding soils can be a significant mitigative factor affecting the potential for downgradient water quality effects of coal ash disposal sites. This further implies that siting new disposal areas which are surrounded by such attenuative soils, or importing such soils for use as site liners may be important mitigative practices on a case-by-case basis.

3. In situations where pond disposal is practiced, the relative importance of a point source discharge can far exceed that of leachate contributions to changes in receiving water quality. However, because of the wide range of variation in disposal site water management practices, this is very much a case-by-case consideration.

4. The use of coal ash ponds as neutralization and admixing media for other intermittent, acidic, metal-rich waste streams (specifically boiler cleaning wastes and possibly coal pile runoff) appears to be an effective mitigative practice under conditions analagous to those at the Allen site. Boiler cleaning wastes were sampled and considered in some detail at this site; coal pile runoff, while not sampled in this program, was a known input to the ash ponds.

5.2.6 Engineering Cost Assessment

5.2.6.1 Engineering Assessment--

Plant Allen, a baseload facility, has a current total nameplate generating capacity of 1,155 MW, employing five units. Plant operation commenced in 1957, with the startup of Units 1 and 2, each unit having a 165 MW nameplate generating capacity. During the three-year period of 1959-1961, inclusive, three units with 275 MW nameplate generating capacities were installed at a frequency of one unit per year. Plant Allen boilers are pulverized coal, tangentially-fired units. Average annual boiler capacity factors during 1979 were 32 and 39 percent for Units 1 and 2, respectively. The newer boilers, Units 3, 4, and 5 had higher load factors during the same period, 57, 61, and 56 percent, respectively.

Air Pollution Control--Units 1 and 2 are equipped with conventional multiple-cyclone, reverse-flow particulate collectors. Units 3, 4, and 5 are equipped with cold-side electrostatic precipitators (ESPs). During the early 1970's, hot-side ESPs were added to each of the five units to effect more efficient fly ash removal. Experimental flue gas conditioning systems have recently been added to Units 1 and 2 in order to improve fly ash collection efficiency. Proprietary chemical additives injected directly into the boiler combustion zone are used for flue gas conditioning. The particulate control systems in use at Plant Allen were tested in October 1979, and were shown to be 97 to 98 percent efficient.

Coal Consumption--Bituminous coal used by this plant is obtained from a number of sources in Virginia, Kentucky, Tennessee and West Virginia. Annual coal consumption for the years 1977 through 1979, inclusive, ranged from 1.72 to 1.95 million metric tons (1.90 to 2.15 million tons). Annual average coal sulfur content remained constant over this period at 1.0 percent, by weight (dry basis). The average annual coal ash content during this period was 12 to 15 percent, by weight. Average heating value of the coal ranged from 28.1 to 28.4 million joules/kg (12,000 to 12,200 Btu/lb).

Waste and Water Management--Fly ash and bottom ash are the only high volume solid wastes produced by this plant. Annual ash production during the next decade is projected to remain constant at approximately 227,000 metric tons (250,000 tons).

Fly ash is conveyed by a vacuum pneumatic system to a hydro-ejector that is used to mix a fly ash/water slurry. The waste is sluiced to the disposal pond. Bottom ash collected in hoppers is directed to clinker grinders and is also sluiced to the disposal pond. Four pipelines are used to transport fly ash and bottom ash to the pond.

Coal pile runoff and plant drainage are intermittently pumped to the disposal pond by way of separate lines. There are two sumps at the Plant Allen site; one collects plant drainage, boiler blowdown, water treatment wastes, and pump sealing water, etc., and a second services surface water runoff from the coal storage area. The sump pumps automatically engage once a specified level of liquid is in the sump. Both sumps discharge into the northeast corner of the disposal pond.

Process flow diagram F-100, Figure 5.8, depicts the waste handling/transport scheme and provides a material balance for this operation.

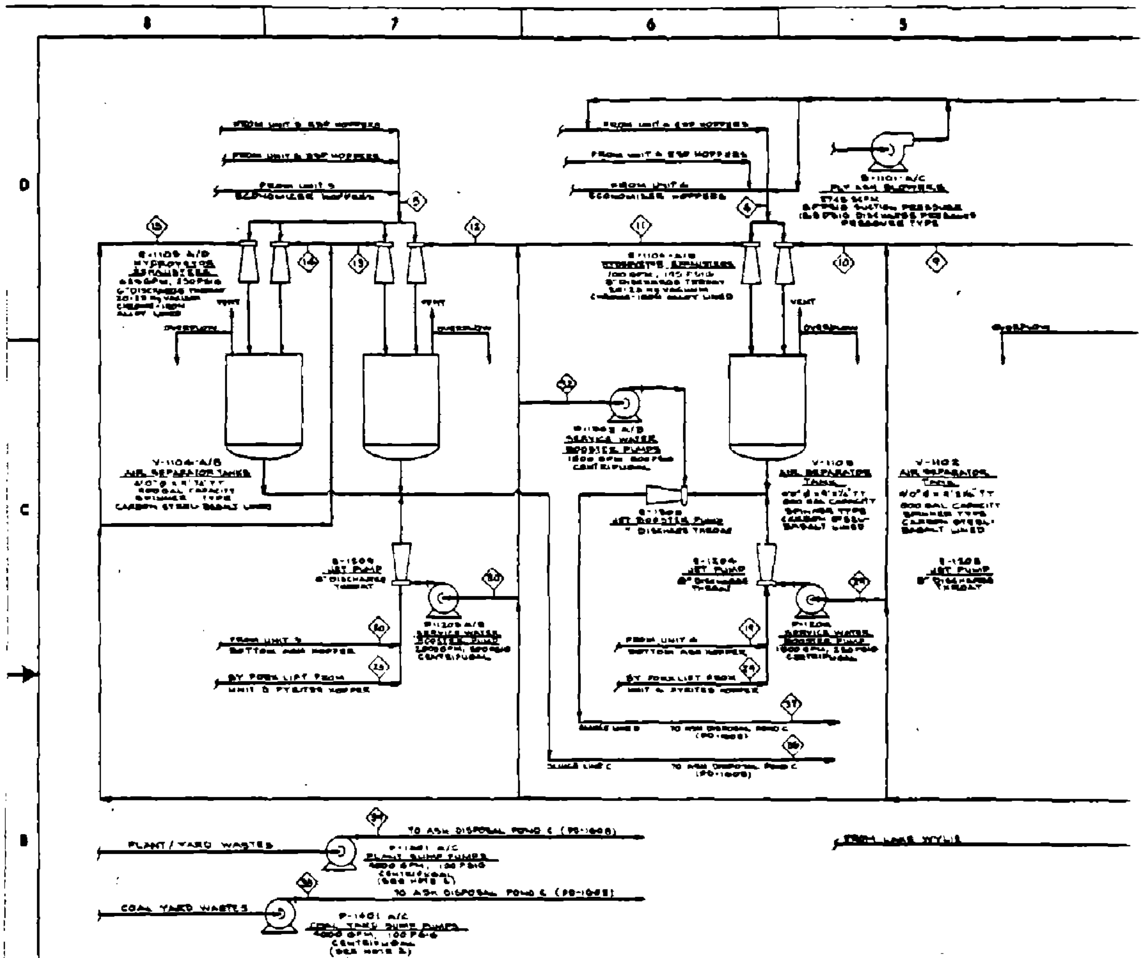
Disposal Operation--The current disposal pond, denoted Pond C, is 590,000 m^2 (146 acres) in size. Effluent from this pond is discharged to Lake Wylie. In prior years, two adjoining ponds, Ponds A and B, were used for coal ash disposal. These ponds were filled with ash and are now retired. Duke Power has undertaken a program of groundwater monitoring at the site and, hence, has installed monitoring wells at various locations around both the active and retired disposal ponds.

In addition to the process descriptions and process flow diagram developed for the Plant Allen coal ash handling and disposal operation, a list of Plant Allen area accounts and a detailed equipment list (divided among modular area accounts) were developed. These are provided as Tables G-1 and G-7, respectively, in Appendix G.

5.2.6.2 Cost Assessment--

Capital and first year annual cost estimates were developed for the coal ash handling and disposal operation at Plant Allen. These were based primarily on the engineering assessment results. However, to provide for consistency among the cost estimates developed for the six sites, it was necessary to specify certain engineering design premises that were consistent for all study sites (e.g., plant service life, load factor, heat rate, etc.). The engineering design premises that pertain to the Plant Allen cost estimates were listed in Table 5.5.

Detailed capital cost estimates for the Plant Allen coal ash handling and disposal system are presented in Appendix G, Table G-13. A summary of the modular capital cost estimates for the Plant Allen system is presented in Table 5.6. This table provides the modular capital costs broken down by waste type. As can be seen from this summary, the cost of the air pollution control system comprises a significant fraction (approximately 65 percent) of the total cost of the environmental control system for the plant. It is also



DESIGN CONDITIONS - TOTAL STREAM FLOW PER NORMAL 24 HOUR DAY (NOTE-5)

DETAIL \ STREAM NO	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 NOTE 4
K TONS ASH/DAY	0.16	0.16	0.29	0.29	0.29	—	—	—	—	—	—	—	—	—	—	0.06
K TONS WATER/DAY	—	—	—	—	—	2.1	2.1	2.1	2.1	2.1	2.1	1.9	1.9	1.9	1.9	N/A
MGPD (WATER)	—	—	—	—	—	0.50	0.50	0.50	0.50	0.50	0.50	0.46	0.46	0.46	0.46	N/A
% SOLIDS	100.0	100.0	100.0	100.0	100.0	0	0	0	0	0	0	0	0	0	0	N/A
SPECIFIC GRAVITY	2.5	2.5	2.5	2.5	2.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	N/A

DETAIL \ STREAM NO	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36
K TONS ASH/DAY	0.007	0.007	0.012	0.012	0.013	—	—	—	—	—	—	—	—	0.45	0.39	0.39
K TONS WATER/DAY	0	0	0	0	0	5.4	5.4	5.4	5.4	8.4	14.6	8.4	66.4	20.4	15.0	16.0
MGPD (WATER)	0	0	0	0	0	1.3	1.3	1.3	1.3	2.0	2.6	1.3	15.9	4.9	3.6	3.8
% SOLIDS	100.0	100.0	100.0	100.0	100.0	0	0	0	0	0	0	0	0	2.2	2.5	2.4
SPECIFIC GRAVITY	2.5	2.5	2.5	2.5	2.5	1.0	1.0	1.0	1.0	[illegible]	1.0	1.0	1.0	1.02	1.02	1.08

N/A = INFORMATION NOT AVAILABLE

8 | 7 | 6 | 5

FIGURE 5.8

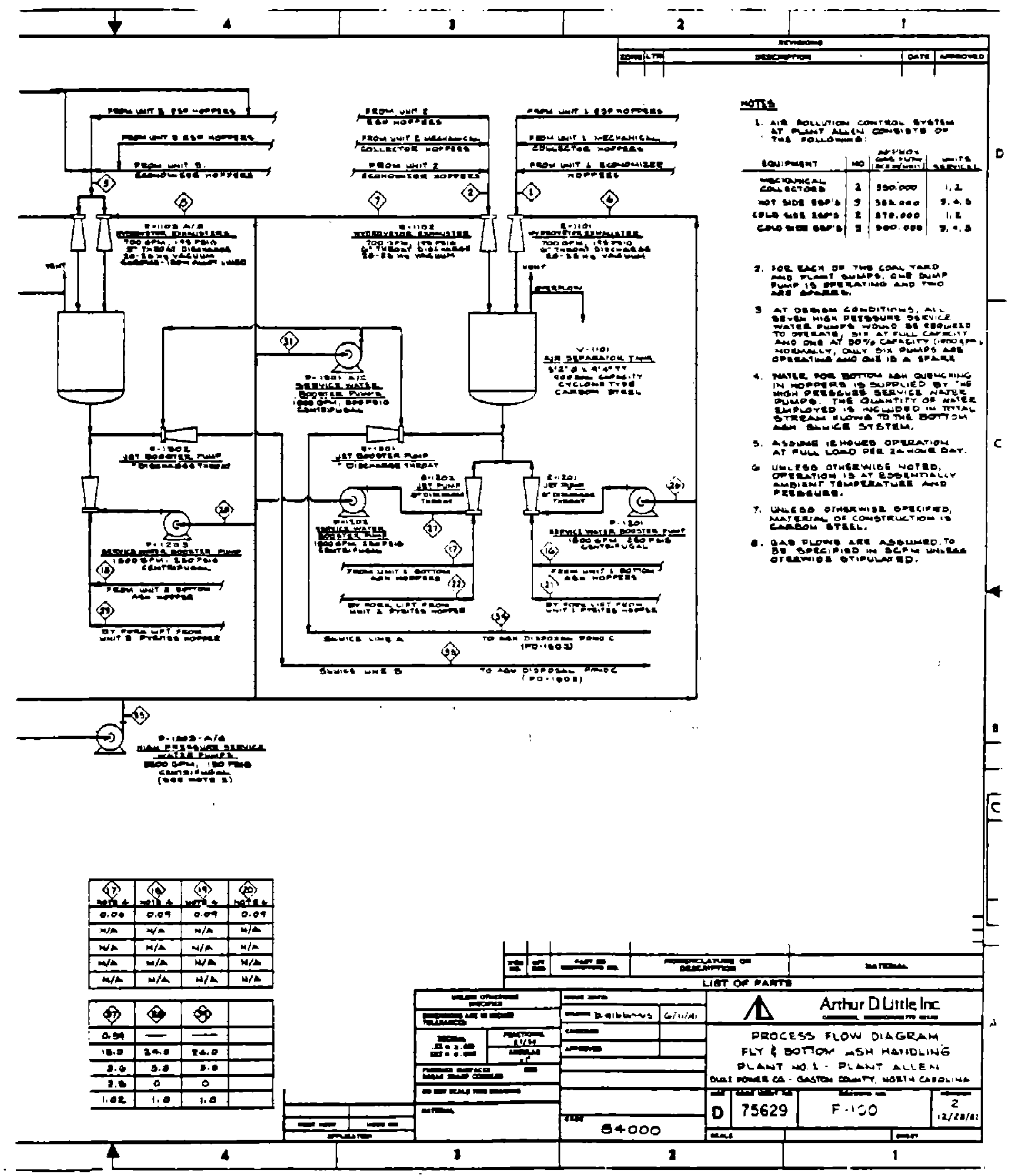

NOTES
LIST OF PARTS
Arthur D Little Inc
PROCESS FLOW DIAGRAM
FLY & BOTTOM ASH HANDLING
D
75629
64000

FIGURE 5.8

TABLE 5.5

SUMMARY OF BASIC ENGINEERING DESIGN PREMISES FOR
ALLEN PLANT
FGC WASTE HANDLING AND DISPOSAL

ENGINEERING DESIGN PREMISES

Power Plant

Plant Size (MW)	1155
Boiler Type	Pulverized Coal
Heat Rate (M joules/kWh; Btu/kWh)	12; 11,400
Location	North Carolina
Service Life (yr)	30
Load Factor (Lifetime Average Percentage)	70

Waste Generated (dry basis)

Fly Ash/Bottom Ash Ratio	75/25
Fly Ash Generation (metric tons/yr; tons/yr)	275,900; 304,200
Bottom Ash Generation (metric tons/yr; tons/yr)	102,000; 112,500
FGD Waste Generation (metric tons/yr; tons/yr)	--
Ash Utilization	None

Coal Properties

Coal Type	Bituminous
Sulfur Content (Percent)	1.0
Ash Content (Percent)	12.0
Heating Value (M joules/kg; Btu/lb)	27.9; 12,000

Air Pollution Control

Particulate Control	Mechanical Collectors (Units 1&2) Cold-Side ESP's (Units 3,4,5) Hot-Side ESP's (Units 1-5)
Particulate Removal (Percent)	>99
Sulfur Oxides Control	None

Disposal Site

Type	Pond
Design Life (yr)	30
Land Area (m^2; acre)	1,104,800; 273
Groundwater Monitoring Wells (Number)	6
Reclamation (Closure)	0.45 m cover soil; 0.15 m top soil: reseeding
Liner (type; m; ft)	None
Distance from Plant (km; mile)	1.6; 1.0

TABLE 5.6

CAPITAL COST SUMMARY[a]
(Late 1982 Estimates)

Plant Name: Allen
Plant Location: Gaston County, North Carolina
Utility Name: Duke Power Company
Nameplate Generating Capacity (MW): 1155

WASTES	CAPITAL COSTS ($1000) Fly Ash	Bottom Ash	Coal Pile Runoff/Plant Wastes	Total
MODULES				
• Waste Handling and Processing	$3,771	$1,433	$ -	$5,204
• Waste Transport	7,920	2,930	-	10,850
• Waste Placement and Disposal (Includes Site Monitoring and Reclamation)	18,349	6,790	-	25,149
SUBTOTAL MODULAR COSTS	$30,050	$11,153	$ -	$41,203($36/KW)
RELATED ENVIRONMENTAL SYSTEMS				
• Miscellaneous Plant Wastes Handling, Transport, and Disposal	-		1,940	1,940
• Air Pollution Control	84,373	-	-	84,373
TOTAL CAPITAL COSTS	$114,423	$11,153	$1,940	$127,516 ($110/KW)

[a] ENR Cost Index = 3931.11 (1913=100)
= 365.97 (1967=100)

Source: Arthur D. Little, Inc. estimates.

evident that the capital cost of solid waste placement and disposal is the largest cost element (approximately 60 percent) when the air pollution control system is not considered. This is commonly the case for ponding operations; in this study the waste placement and disposal module for ponding operations typically comprised 55 to 65 percent of the non-air pollution control environmental system costs. The Plant Allen capital cost estimate is consistent with this thesis.

Comparison of the Plant Allen waste handling and disposal system (excluding related environmental systems) capital costs ($36/kW) to those for other plants evaluated under this program that practice pond disposal (the Sherburne County Plant at $43/kW and the Smith Plant at $47/kW) indicates that this system has the lowest capital costs. This is primarily due to savings that result from economies of scale (i.e., Plant Allen has a nameplate generating capacity of 1155 MW, while that for the Smith Plant is only 340 MW) and from the fact that the pond construction did not require expensive materials (i.e., the Plant Allen pond is unlined, compared to that at the Sherburne County Plant that was lined with clay at an added expense). However, the difference among the Plant Allen capital cost estimate and those for the other plants that use pond disposal is not as pronounced as one might expect. This is because Plant Allen, with five boilers, has four distinct and separate coal ash handling and transport systems. The capital cost for this module is relatively high, since it is actually comprised of four small-scale systems and therefore exhibits very little economy of scale. In addition, the distance from the plant to the disposal site at Plant Allen is approximately four times as great as that at the Smith Plant.

A detailed annual cost estimate was prepared for the Plant Allen system (Table G-19, Appendix G). A modular summary of this estimate, Table 5.7, provides a less detailed account of these costs.

Annual costs for the three sites evaluated which practice ponding of FGC wastes were relatively similar in value. The unit annual cost for ponding at Plant Allen ($23.70/dry metric ton) is the lowest of the three; the unit cost for the Smith Plant is $25.10/dry metric ton while the Sherburne County Plant cost is $26.60/dry metric ton. The lower cost at Plant Allen (1155 MW) indicates some cost savings due to economies of scale (with respect to the Smith Plant 340 MW), however, one might expect this to be more dramatic. The fact that Plant Allen, with five boilers, has four distinct and separate coal ash handling and transport systems reduces economies of scale that one might expect. As with the capital costs, the major annualized cost element is due to the waste placement and disposal module, which typically contributes 45 to 55 percent of the total annual cost. This is primarily due to the large contribution of disposal ponds capital charges to the annualized cost. This, again, illustrates that pond disposal is highly capital intensive.

TABLE 5.7

ANNUAL COST SUMMARY
(Late 1982 Estimates)[a]

Plant Name: Allen
Plant Location: Gaston County, North Carolina
Utility Name: Duke Power Company

Operating Load Factor (percent): 70
Name Plant Generating Capacity (MW): 1155
Waste Generation (dry metric tons/yr):
Fly ash - 275,900; Bottom ash - 102,000

WASTES	ANNUAL COSTS ($1000) Fly Ash	Bottom Ash	Coal Pile Runoff and Plant Wastes	Total
MODULES				
• Waste Handling and Processing	$1,216.1	$ 887.6	$ -	$2,103.7
• Waste Transport	1,903.6	703.5	-	2,607.1
• Waste Placement and Disposal (Includes Site Monitoring and Reclamation)	3,092.9	1,143.8	-	4,236.7
SUBTOTAL - MODULAR COSTS	$6,212.6	$2,734.9	$ -	$8,947.5 ($23.70/dry metric ton)
RELATED ENVIRONMENTAL SYSTEMS				
• Miscellaneous Plant Waste Handling and Transport	$ -	$ -	$551.5	$ 551.5
• Air Pollution Control	NA[b]	-	-	NA[b]
TOTAL ANNUAL COSTS	$6,212.6 + NA[b]	$2,734.9	$551.5	$9,499.0 + NA[b]

[a] ENR Cost Index = 3931.11 (1913=100)
365.97 (1967=100)

[b] NA = Information not available

Source: Arthur D. Little, Inc. estimates.

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QUARLES EXHIBIT 4

DEC RESPONSE TO NCPS DR 36-2

Docket No. e-7, Sub 1214

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 36-2

Docket No. E-7, Sub 1146

Date of Request: **January 2, 2018**
Date of Response: **January 15, 2018**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 36-2, was provided to me by the following individual(s): Trudy H. Morris, Project Manager II, Project Portfolio Manager, and was provided to NC Public Staff under my supervision.

John Burnett
Deputy General Counsel
Duke Energy Carolinas

NCPS 36-2

Request:

Please state how many voluntary monitoring wells were installed, where they were installed (plant name, whether each well was at, beyond, or inside the compliance boundary, and whether each well was up-gradient or downgradient), when they were installed, and if any of these wells provided data that indicated contaminants from coal ash were migrating from each ash basin. For wells that provided data showing exceedances, please state the dates that the exceedances were identified in well samples, the type (constituent) for each exceedance, whether the exceedance was due to natural background levels or due to coal ash or if there was insufficient background data to determine, and what corrective action was taken and when it was taken with respect to each exceedance.

Response:

At the time DE Carolinas was engaged in voluntary groundwater monitoring, it did not have sufficient information to determine natural background levels. At some sites, the company did install background/upgradient wells, but the limited data generated were more appropriate for qualitative rather than quantitative comparisons. In other words, the limited data were not sufficient nor was it intended to support the kind of statistical analysis now required by NCDEQ to generate the PBTVs. During the voluntary monitoring period, NCDEQ never objected to the company's qualitative analysis or moved to set more explicit background levels. Although limited, the data, as compared to available North Carolina groundwater quality surveys, indicate that the constituents of concern were naturally occurring and could be due to background conditions. For example, at Allen, the constituents of concern beyond the compliance boundary were pH, iron, manganese, and vanadium, all of which can occur naturally in the Piedmont Region of North Carolina. Subsequent analysis, which was not required by DEQ until 2016, has resulted in PBTVs above the default 2L standards for these parameters. Based on the more robust data set now available as a result of groundwater monitoring requirements in NPDES, it is possible that some exceedances identified in voluntary wells were due to naturally occurring conditions and some were affected by the ash basin. However, DE Carolinas does not have a comparison of voluntary well monitoring data against PBTVs to provide a well-by-well breakdown.

Initial results appeared consistent with naturally occurring conditions, so between the installation of the voluntary monitoring wells and 2009, DE Carolinas continued monitoring the wells and submitting semi-annual reports to the NCDEQ. In 2009, DE

Carolinas began to work with the department to relocate and install new wells at the ash basin compliance boundaries, as monitoring was added to NPDES permits. In 2011, the Department issued the Policy for Compliance Evaluation of Long-Term Permitted Facilities with No Prior Groundwater Monitoring Requirements, whereafter DE Carolinas began to work through the assessment process detailed therein. The 2011 policy under which DE Carolinas had been operating was ultimately rescinded by NCDEQ in 2015; however, DE Carolinas has participated in CAMA's assessment and corrective provisions since 2014.

Please also see the attached documents.

PS_36_Summary_Voluntary_Well_Exceeda PS_36_Summary_Voluntary_Well_Exceeda PS_36_Summary_Voluntary_Well_Exceeda PS_36_Summary_Voluntary_Well_Exceeda PS_36_Summary_Voluntary_Well_Exceeda

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WILSON EXHIBIT RW-1

RESUME

Docket No. e-7, Sub 1214

Synapse
Energy Economics, Inc.

Rachel Wilson, Principal Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 2 I Cambridge, MA 02139 I 617-453-7044
rwilson@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Principal Associate*, April 2019 – present, *Senior Associate*, 2013 – 2019, *Associate*, 2010 – 2013, *Research Associate*, 2008 – 2010.

Provides consulting services and expert analysis on a wide range of issues relating to the electricity and natural gas sectors including: integrated resource planning; federal and state clean air policies; emissions from electricity generation; electric system dispatch; and environmental compliance technologies, strategies, and costs. Uses optimization and electricity dispatch models, including Strategist, PLEXOS, EnCompass, PROMOD, and PROSYM/Market Analytics to conduct analyses of utility service territories and regional energy markets.

Analysis Group, Inc., Boston, MA.

Associate, 2007 – 2008, *Senior Analyst Intern*, 2006 – 2007.

Provided litigation support and performed data analysis on various topics in the electric sector, including tradeable emissions permitting, coal production and contractual royalties, and utility financing and rate structures. Contributed to policy research, reports, and presentations relating to domestic and international cap-and-trade systems and linkage of international tradeable permit systems. Managed analysts' work processes and evaluated work products.

Yale Center for Environmental Law and Policy, New Haven, CT. *Research Assistant*, 2005 – 2007.

Gathered and managed data for the Environmental Performance Index, presented at the 2006 World Economic Forum. Interpreted statistical output, wrote critical analyses of results, and edited report drafts. Member of the team that produced *Green to Gold*, an award-winning book on corporate environmental management and strategy. Managed data, conducted research, and implemented marketing strategy.

Marsh Risk and Insurance Services, Inc., Los Angeles, CA. *Risk Analyst*, Casualty Department, 2003 – 2005.

Evaluated Fortune 500 clients' risk management programs/requirements and formulated strategic plans and recommendations for customized risk solutions. Supported the placement of $2 million in insurance premiums in the first year and $3 million in the second year. Utilized quantitative models to create loss forecasts, cash flow analyses and benchmarking reports. Completed a year-long Graduate Training Program in risk management; ranked #1 in the western region of the US and shared #1 national ranking in a class of 200 young professionals.

EDUCATION

Yale School of Forestry & Environmental Studies, New Haven, CT
Masters of Environmental Management, concentration in Law, Economics, and Policy with a focus on energy issues and markets, 2007

Claremont McKenna College, Claremont, California
Bachelor of Arts in Environment, Economics, Politics (EEP), 2003. *Cum laude* and EEP departmental honors.

School for International Training, Quito, Ecuador
Semester abroad studying Comparative Ecology. Microfinance Intern – Viviendas del Hogar de Cristo in Guayaquil, Ecuador, Spring 2002.

ADDITIONAL SKILLS AND ACCOMPLISHMENTS

- Microsoft Office Suite, Lexis-Nexis, Platts Energy Database, Strategist, PROMOD, PROSYM/Market Analytics, EnCompass, and PLEXOS, some SAS and STATA.
- Competent in oral and written Spanish.
- Hold the Associate in Risk Management (ARM) professional designation.

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Resume dated October 2019

I/A

SIERRA CLUB

WILSON EXHIBIT RW-4

GEORGIA STIPULATION

Docket No. e-7, Sub 1214

I/A

COMMISSIONERS:

LAUREN "BUBBA" McDONALD, CHAIRMAN
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TRICIA PRIDEMORE
JASON SHAW

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EXECUTIVE DIRECTOR

REECE McALISTER
EXECUTIVE SECRETARY

FILED
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EXECUTIVE SECRETARY
G.P.S.C.

DOCKET# 42310, 42311
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Georgia Public Service Commission

(404) 656-4501
(800) 282-5813

244 WASHINGTON STREET, SW
ATLANTA, GEORGIA 30334-5701

FAX: (404) 656-2341
www.psc.state.ga.us

Docket No: 42310 **In Re: Georgia Power Company's 2019 Integrated Resource Plan and Application for Certification of Capacity from Plant Scherer Unit 3 and Plant Goat Rock Units 9-12, Application for Decertification of Plant Hammond Units 1-4, Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6 and Plant Riverview Units 1-2.**

Docket No. 42311 **In Re: Georgia Power Company's 2019 Application for the Certification, Decertification, and Amended Demand-Side Management Plan.**

ORDER ADOPTING STIPULATION AS AMENDED

APPEARANCES:

On behalf of Georgia Public Service Commission:

JEFFREY STAIR, Attorney
PRESTON THOMAS, Attorney
-and-
DANIEL WALSH, Attorney
Office of the Attorney General

On behalf of Georgia Power Company:

KEVIN C. GREENE, Attorney
BRANDON MARZO, Attorney
STEVE HEWITSON, Attorney

ALAN R. JENKINS, Attorney

<u>On behalf of Concerned Ratepayers of Georgia:</u>

STEVEN PRENOVITZ
BEN STOCKTON

<u>On behalf of Emory University</u>:

WILLIAM W. MAYCOCK, Attorney
R. DANIELLE BURNETTE, Attorney

<u>On behalf of Georgia Association of Manufacturers and Georgia Industrial Group</u>:

CHARLES B. JONES, III, Attorney

<u>On behalf of Georgia Distributed Generation Group, Inc.</u>:

DARGAN SCOTT COLE, Attorney

<u>On behalf of Georgia Interfaith Power & Light and Partnership for Southern Equity</u>:

KURT EBERSBACH, Attorney
STACEY SHELTON, Attorney
CHRISTINA ANDREEN, Attorney

<u>On behalf of Georgia Large Scale Solar Association</u>:

WILLIAM BRADLEY CARVER, SR., Attorney

<u>On behalf of Solar Energy Industries Association, Inc., and Georgia Solar Energy Association, Inc.</u>:

NEWTON M. GALLOWAY, Attorney
TERI M. LYNDALL, Attorney
STEVEN L. JONES, Attorney

<u>On behalf of Georgia Watch</u>:

LIZ COYLE

BERNETA L. HAYNES, Attorney

On behalf of McFinney, LLC:

JOE McDONOUGH, Managing Partner

On behalf of Resource Supply Management:

JAMES CLARKSON

On behalf of the Sierra Club:

ROBERT JACKSON, Attorney
ZACHARY M. FABISH, Attorney
KASEY STURM, Attorney

On behalf of Southern Alliance for Clean Energy:

ROBERT B. BAKER, Attorney

On behalf of Southern Renewable Energy Association:

BRUCE BURCAT, Attorney

On behalf of Southface Energy Institute and Vote Solar:

STEPHEN E. O'DAY, Attorney

BY THE COMMISSION:

On January 31, 2019, Georgia Power Company ("Georgia Power" or the "Company") submitted to the Georgia Public Service Commission ("Commission") an Application for Integrated Resource Plan ("IRP" or "Plan") for approval pursuant to O.C.G.A. § 46-3A-1 *et. Seq.* Included in the Company's filing was an Application for Certification Capacity from Plant Scherer Unit 3 and

Plant Goat Rock Units 9-12, Application for Decertification of Plant Hammond Units 1-4, Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6 and Plant Riverview Units 1-2, Docket No. 42310. The Company also simultaneously submitted an Application for the Certification, Decertification, and Amended Demand-Side Management Plan ("DSM Application") Docket No. 42311.

JURISDICTION AND AUTHORITY

Georgia Power is a public electric utility serving retail customers within the State of Georgia. Georgia Power is one of the retail operating companies of which the Southern Company system is comprised. This Commission has jurisdiction over Georgia Power's IRP and DSM Application pursuant to O.C.G.A. § 46-2-20, 46-2-21, 46-2-23 generally, and the IRP Act in particular.

The IRP Act requires the Company to file an Integrated Resource Plan at least every three years.[1] The Company's obligations with respect to the information that is filed is set forth pursuant to criteria identified in the Commission's IRP Rules. A "plan" is defined in the Act as an Integrated Resource Plan that contains the utility's electric demand and energy forecast for at least a 20-year period; program for meeting the requirements shown in its forecast in an economical and reliable manner; the analysis of all capacity resource options, including both demand-side and supply-side options; and the assumptions used and the conclusions reached with respect to the effect of each capacity resource option on the future cost and reliability of electric service. The Plan also must:

(A) Contain the size and type of facilities which are expected to be owned or operated in whole or in part by such utility and the construction of which is expected to commence during the ensuing ten years or such longer period as the Commission deems necessary and shall identify all existing facilities intended to be removed from service during such period or upon completion of such construction;

[1] O.C.G.A. § 46-3A-2.

(B) Contain practical alternatives to the fuel type and method of generation of the proposed electric generating facilities and set forth in detail the reasons for selecting the fuel type and method of generation;

(C) Contain a statement of the estimated impact of proposed and alternative generating plants on the environment and the means by which potential adverse impacts will be avoided or minimized;

(D) Indicate, in detail, the projected demand for electric energy for a 20-year period and the basis for determining the projected demand;

(E) Describe the utility's relationship to other utilities in regional associations, power pools, and networks;

(F) Identify and describe all major research projects and programs which will continue or commence in the succeeding three years and set forth the reasons for selecting specific areas of research;

(G) Identify and describe existing and planned programs and policies to discourage inefficient and excessive power use; and

(H) Provide any other information as may be required by the Commission.[2]

The Commission is required under O.C.G.A. § 46-3A-2 to make determinations as to the adequacy of the IRP and to ensure that the utility's Plan has appropriately addressed numerous matters. There must be a determination that the forecast requirements contained in the Plan are based on substantially accurate data and an adequate method of forecasting.[3] The Commission must also find that the Plan identifies and considers any present and projected reductions in the demand for energy that may result from measures to improve energy efficiency in the industrial, commercial, residential, and energy-producing sectors of the state.[4]

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[2] O.C.G.A. § 46-3A-1(7).
[3] O.C.G.A. § 46-3A-2(b)(1).
[4] O.C.G.A. § 46-3A-2(b)(2).

Further, the Commission must determine whether the Plan adequately demonstrates the economic, environmental, and other benefits to the state and to customers of the utilities, associated with the following possible measures and sources of supply:

(A) Improvements in energy efficiency;

(B) Pooling of power;

(C) Purchases of power from neighboring states;

(D) Facilities that operate on alternative sources of energy;

(E) Facilities that operate on the principle of cogeneration or hydro-generation; and

(F) Other generation facilities and demand-side options.[5]

After hearings have been conducted on a Plan, the Commission may approve the IRP; approve it subject to stated conditions; approve it with modifications; approve it in part and reject it in part; reject the plan as filed; or provide an alternate plan, upon determining that this is in the public interest.[6]

An electric utility is entitled to recover the approved or actual cost, whichever is less, of any certificated demand-side capacity option in rates, along with an additional sum.[7] In determining the additional sum, the Commission "shall consider lost revenues, if any, changed risks, and an equitable sharing of benefits between the utility and its retail customer."[8]

BACKGROUND AND STATEMENT OF PROCEEDINGS

On February 2, 2019, the Commission issued its Procedural and Scheduling Order in both Dockets setting forth the dates for filing of testimony and briefs, as well as the dates for the hearings in this matter. These proceedings were declared to be contested cases as the term is defined in O.C.G.A. § 50-13-13 and were also held to encompass complex litigation pursuant to O.C.G.A. §

[5] O.C.G.A. § 46-3A-2 (b)(3).
[6] GPSC Utility Rule 515-3-4-.01(2).
[7] O.C.G.A. § 46-3A-9
[8] *Id.*

9-11-33(a). The two proceedings were assigned Docket Numbers 42310 and 42311, respectively, and combined for purposes of administrative efficiency and convenience.

Pursuant to O.C.G.A. § 46-3A-5(c), the Commission established the fee for review of the IRP within sixty days of the filing of the applications. On March 16, 2019, the Commission concluded that six hundred eighteen thousand three hundred eighty-five dollars ($618,385.00) was the appropriate fee for review and analysis of the Company's filing.

On April 8, 2019, in accordance with the Procedural and Scheduling Order, the Commission heard direct testimony of Georgia Power's two panels of witnesses: (1) Jeffery R. Grubb, Narin Smith, Michael A. Bush and Jeffrey B. Weathers; and (2) Mark S. Berry and Aaron D. Mitchell.

The Commission conducted hearings on the direct cases of the Public Interest Advocacy Staff ("PIA Staff") and intervening parties in both Dockets on April 13 – 15, 2019. The PIA Staff sponsored several witnesses and witness panels: a panel consisting of Ralph Smith and Robert Trokey; panel witnesses Philip Hayet, Tom Newsome and Stephen Baron; individual testimony of John Hutts and John Chiles; panel witnesses Jamie Barber, John Kaduk, Richard Spellman and John Athas; and lastly, a panel consisting of Jamie Barber, Nick Cooper and Richard Spellman.

The Intervening parties testified as follows: Commercial Group - Steve Chriss; Concerned Ratepayers of Georgia - Steven C. Prenovitz; Emory University - panel Joan Kowal and Edward T. Borer, Jr.; Georgia Center for Energy Solutions - Peter J. Hubbard; Georgia Distributed Generation Group - panel Dr. Ben Johnson and Ryan Sanders: Georgia Interfaith Power & Light and Partnership for Southern Equity - James Wilson; Georgia Interfaith Power & Light and Partnership for Southern Equity, Southface Energy Institute and Vote Solar - William M. Cox; Georgia Large Scale Solar Association - panel John Sterling, Lynnae Willette, John Vanhoe and Arne Olson; Georgia Solar Energy Industries Association, Inc. - panel William M. Cox and Karl R. Rabago; Georgia Solar Energy Association, Inc. - panel Casey M. Busch, Steve A. Chiarello, George N. Mori and Thatcher R. Young; Georgia Watch - panel of Charles Harak and Lindsey Robbins; Sierra Club - Rachel S. Wilson; Southern Alliance for Clean Energy and

Southern Renewable Energy Assoc. - Mark Detsky; Southern Alliance for Clean Energy - panel Theresa Perry, Brendan J. Kirby and Forest Bradley - Wright and panel John D. Wilson and Bryan A. Jacob; and Southern Renewable Energy Assoc. - Michael Goggin and Joshua D. Rhodes.

On June 6, 2019, Georgia Power and PIA Staff executed and submitted a Stipulation designed to resolve all the issues that were raised in these two dockets. (See Attachment A) Subsequently, on June 11, 2019, The Commercial Group, Georgia Industrial Group ("GIG") and Georgia Association of Manufacturers ("GAM") signed the Stipulation; Georgia Watch signed the Stipulation on June 18, 2019; and the Georgia Distributed Generation Group signed the Stipulation thereafter. The Stipulation along with the Company's rebuttal testimony were addressed by Georgia Power's witness panel Jeffrey R. Grubb, Narian Smith, Michael A. Bush and Jeffrey B. Weathers on June 11, 2019.

The Stipulation contains 43 provisions. There are twenty-seven provisions pertaining to the Supply Side Plan and sixteen provisions pertaining to the Demand Side Plan as outlined in Attachment A.

On June 24, 2019 briefs and/or proposed orders were filed by parties in the case. Five signing parties filed briefs in support of the Stipulation and nine non-signing parties filed brief and/or proposed orders making the following recommendations.

NON-SIGNING PARTIES' POSITIONS

Georgia Interfaith Power & Light and Partnership for Southern Equity – GIPL & PSE ("GIPL")

GIPL recommended that the Commission amend the Stipulation to include and require the Company to: (1) model a scenario in which energy efficiency measures are allowed to compete against supply-side measures. Additionally, the DSM Plan must demonstrate optimization of DSM resources, including program budget and details concerning how the Plan balances economic efficiency and rate impacts; (2) develop its 2022 IRP, to allow demand-side resources to compete with supply-side resources; (3) collaborate with Staff and interested stakeholders, over the next year, to model ways to meet a 1% energy efficiency savings target by 2025; (4) continue offering the Automated Benchmarking Tool and to promote the tool; (5) increase funding of its low-income energy efficiency program to $400,000 in 2020, and $500,000 in each of the two subsequent years so that by 2022 the total funding reaches $4 million; (6) work with Staff and interested stakeholders to conduct a data-driven and collaborative conversation over the next year. The group will submit a report to the Commission by January 31, 2021 to inform 2022 IRP planning; (7) add a total of 3,000 MW of renewable energy, over the next three years, including 250 MW of distributed generation. The DG portion must include at least 100 MW of a standard offer, buy-all/sell-all program, with a fixed price levelized over thirty years set at 5 percent below avoided cost; (8) reevaluate and update as appropriate the avoided cost methodology used in Docket 4822, over the next year, while allowing for participation by interested stakeholders; (9) designate at least 100 MW of utility-scale solar capacity to a municipal subscription program designed for government customers; (10) dedicate 10 MW of its approved storage capacity to be deployed in resilience hubs in underserved and vulnerable rural and urban communities for critical emergency services. The Company and Staff will work together to identify and gather input from interested communities on their needs; (11) eliminate winter declining block rates in the upcoming 2019 rate case and, before the 2022 IRP, investigate scaling up the Company's residential thermostat demand-response program to address winter reliability concerns; (12) approve its coal ash clean-up strategy only for those methods that comply with the federal and state CCR Rules; and (13) continue operating its MATS controls to control emission of mercury and other air toxins irrespective of any state or federal attempts to weaken existing standards for the control of mercury and other air toxins. (GIPL/PSE Brief at pp. 2-4).

Georgia Large Scale Solar Association

Georgia Large Scale Solar Association recommended that the Commission adopt the Stipulation with the following changes: (1) Increase by 1,000 MWs from the stipulated agreement, utility scale solar program. The procurement(s) shall be completed by 2021 with all procurements accepting commercial operations dates of 2023 (1500 to 2500). (2) Hold a break out session between PSC Staff and interested Intervenors at the conclusion of this IRP to update the Renewable Cost-Benefit Framework ("RCB") and develop a methodology to value solar + storage in an all source procurement prior to the 2022-2023 capacity-based RFP and prior to the onset of the Company's 2022 resource planning. (GLSSA Brief at pp. 1-2).

Georgia Solar Energy Assoc., Inc. & Georgia Solar Energy Industries Assoc., Inc. (GSEA & GSEIA)

Georgia Solar recommended that the following directives be included in the Stipulation: (1) Direct the Company to develop and implement a Customer-Sited BA/SA tariff. (2) Revise the program guidelines for customer-sited program following the precedent of the Customer-Sited BA/SA program in REDI. (3) Expand the RNR tariff to include small and medium business customers with solar DG needs between 250 kW to 3 MW. (4) Revise the RCB to properly consider the geographic benefit and cost savings to the Company from deployment of solar generation at or near load. And (5) Modification of PURPA avoided costs and RCB for application to basic QFs. (GSEA & GSEIA Brief at p. 17)

Resource Supply Management - ("RSM")

RSM recommended that participation in DSM programs be voluntary for all customers and that customers should be allowed to opt-out of Demand Side Measures along with the associated surcharges on customer bills. (RSM Brief at p. 1).

Sierra Club

Sierra Club recommended that the Commission direct Georgia Power to (1) significantly expand its procurement of renewable resources, (2) retire Plant Bowen or lower the caps on expenditures in line with those placed on Hammond and McIntosh in the 2016 IRP and that the Commission state that exceedances of the caps are not recoverable from ratepayers and (3) in future IRP dockets, employ resource dispatch modeling that analyzes all resource types head-to-head. (Sierra Club Brief at p. 1).

Southern Alliance for Clean Energy, Inc. ("SACE")

SACE recommended the following: (1) the amount of renewable energy generation be increased to a minimum of 3,000 MW; (2) the amount of distributed generation be expanded to 450 MW and any amount of distributed generation not under development or contract by January 1, 2022, automatically be allocated to either the CRSP or REDI II programs; (3) the Company be ordered to update its analysis of technical feasibility of renewable energy factoring in the flexible operating mode of solar; (4) the DSM Advocacy Program be adopted or double the amount of energy efficiency savings in the DSM plan and make the Manufactured Homes Program a pilot program; (5) the Company be directed to use an All-Source Bidding process in future RFPs that does not exclude any type of generation resource; (6) Plant Wansley be included in the 2022-23 capacity RFP; (7) the seven critical improvements and additional enhancement to the CRSP program recommended by SACE witness Perry be adopted; (8) the Company be directed to reexamine the generation remix cost method, the support capacity, the winter reserve requirements in the RCB Framework and recalculate the reserve margins and capacity worth factor tables prior to issuing any RFPs; (9) the Company's additional sum proposal be redesigned to ensure risk and equitable sharing of benefits are considered; and (10) all parties may intervene and fully participate in any proceedings regarding the RCB Framework, the RFPs for all renewable energy generation and all semi-annual reviews of the Company's coal combustion residual compliance efforts. (SACE Brief at pp. 16-17).

Southern Renewable Energy Association ("SREA")

SREA recommended that the IRP be rejected for not providing for a sufficiently sized, nor suitably timed, renewable energy request for proposal ("RFP") process. SREA requested that the Commission consider the following findings and recommendations: (1) Determine that the 1,500 MW solicitation for large scale renewables as part of the Customer Renewable Supply Procurement (CRSP) program is too small and fails to incorporate of the benefits of various renewable resources. (2) The Commission modify CRSP to include a competitive solicitation of at least 3,000 MW's of renewable energy. (3) Within CRSP, 1,000 MW's of large-scale renewable energy resources should be dedicated for customer subscription for new and existing customers with a minimum of 3 MW's of aggregated load. (4) The remaining 2,000 MW's (or greater) of large-scale renewable energy resources within CRSP should be provided for the entire customer base. (5) Before ITC tax incentives begin to phase out, the Company needs to develop a RFP process that produces proposals, evaluates results, and allows the Commission to review and approve proposals in a much more expedient manner. (6) The Company should be required to include fuel hedging as a placeholder in the Renewable Cost Benefit (RCB) Framework. This Framework should also consider the benefits of solar energy, wind power, and energy storage as long-term price hedges for volatile fossil fuel pricing. (7) The Commission should modify the proposed "Capacity Requests for Proposals" (RFPs) to become "All-Source" RFPs. And (8) The Commission should order that intervening parties in this docket will be formally included in discussions regarding the proposed CRSP program, the updated RCB Framework, Capacity RFP's, and the Battery Energy Storage System RFP. (SREA Brief at pp. 3-4).

Southface & Vote Solar

Southface and Vote Solar contend that there are several deficiencies in the proposed Stipulation and recommended that the Commission:

Supply Side Plan:

(1) Increase total renewable energy procurement in this IRP to at least 3,000 MW. (2) Expand the 150 MW DG procurement proposed in the Stipulation to 250 MW of capacity, including 150 MW of competitively bid DG and 100 MW of fixed price DG to be set at 5% below avoided cost. (3) Increase the overall utility-scale solar procurement by up to 100 MW and dedicate this capacity to a municipal customer subscription program open to existing government customer load. (4) Open a proceeding under Dockets 4822 and 16573 to examine Georgia Power's calculation of avoided cost. (5) Proposed continuation of negotiations between the Company and PIA Staff on the RCB Framework include interested Intervenors that were party to the 2019 IRP. (6) Dedicate at least 10 MW of the approved energy storage capacity to projects that both demonstrate and support local resilience. (7) Consider support for implementation of the Emory Micro-Grid project.

Demand Side Plan

(1) Require higher energy savings performance for Georgia Power's DSM portfolio now. In addition, requested the Commission direct the 2020-2021 DSM Work Group to thoroughly

explore the option of adopting a DSM performance target for Georgia Power that provides the backdrop for a 2022 DSM program portfolio that will achieve savings equal to one percent of prior year retail sales by 2025. (2) Direct the DSM Work Group to produce a DSM policy framework that clarifies the Commission's perspective on the costs and benefits of DSM resources and outlines positions of agreement among the DSM Work Group participants. (3) Support implementation of a modest industrial DSM pilot program targeting small and medium industrial customers. (4) Support the Stipulation provision aimed at capping the dramatic growth in DSM program non-incentive costs. (5) Support the Stipulation provision to further reduce administrative costs for the Income Qualified Tariff Based proposed pilot program and ensure the Company continues to seek input of interested stakeholders on Pilot program design and implementation specifics. (6) Support continued operation of Automated Benchmarking Tool by Georgia Power for the next three years. And (7) Expand the Stipulation provision regarding final DSM program plans to include a requirement that Georgia Power publish the Final Program Plans in the docket. (Southface & Vote Solar Brief at pp. 25-27).

Emory University

Emory University filed testimony promoting the proposal that Georgia Power and Emory University work together to develop microgrid technologies for use around the state, specifically around Emory's campuses. In the Stipulation, Supply Side Plan provision 27 specifically states that neither the PIA Staff nor the Company recommended the Emory microgrid project. However, if the Commission decided that it is appropriate to move forward with the project, both the PIA Staff and Company recommended that it be done so only on the condition that, if the project costs exceed the benefits to other ratepayers, Emory agrees to pay the difference. Emory University was silent on provision 27 deciding not to file a brief on the matter. However, during witness testimony, they stated that the university would not pursue the microgrid with Georgia Power if the cost burden to other customers outweighed the benefits. (Tr.1789).

Other Parties of Record

Testimony was not filed by the following non-signing parties: McFinney, LLC and Resource Supply Management. Briefs were not filed by the following non-signing parties: Concerned Ratepayers of Georgia, Emory University, Georgia Center for Energy Solutions, and McFinney, LLC.

FINDINGS OF FACT AND CONCLUSIONS OF LAW

1.

To ensure that the competing interests of all parties were properly considered, the Commission carefully considered the Stipulation, Attachment A, entered into by the Stipulating Parties of record including the testimony given and the various exhibits entered by all of the parties. The Commission finds and concludes that the terms of the Stipulation are supported by the evidence in the record and is a fair and reasonable resolution which appropriately strikes the balance of the interest of all Parties while ensuring system reliability and providing energy at a reasonable cost. Therefore, the Commission approves and adopts the Stipulation as amended below.

2.

Paragraph 3 of the Stipulation states that:

The Company shall procure 1,500 MW alternating current ("AC") of new utility scale renewable resources, defined as projects greater than 3 MW AC. 500 MW of these new resources shall be dedicated to all retail customers. The Customer Renewable Supply Procurement Program ("CRSP") is approved and shall be increased such that it will procure energy from 1,000 MW (600 MW of utility scale renewable resources for subscription by existing CRSP eligible customers, and 400 MW for subscription by CRSP eligible customers adding new load). The Utility scale procurement shall take place through two separate Requests For Proposals ("RFP"). The first RFP is expected to be issued in 2020 and will seek 250 MW of renewables with in-service dates of 2022 and 2023 for all retail customers, 300 MW for subscription by existing CRSP eligible customers, and up to 400 MW for subscription by CRSP eligible customers adding new load. The second RFP is expected to be issued in 2021 and will seek 250 MW of renewables with in-service dates of 2023 and 2024 for all retail customers, 300 MW for subscription by existing CRSP eligible customers and 0 to 400 MW for subscription by CRSP eligible customers adding new load (0 MW to 400 MW represents the remainder of any resources not procured for subscription by CRSP eligible customers adding new load in the first RFP). Any capacity for new load that remains unsubscribed at the end of the second RFP would be offered to any existing CRSP eligible customers whose Notice of Intent ("NOI") capacity request had not been fully met. Any remaining amounts

> *procured through the RFPs for CRSP but unsubscribed by CRSP participants will be used to serve all retail customers.*

The Commission finds and concludes it is more reasonable and appropriate to increase the amount of the utility scale renewable procurement to 2000 megawatts alternating current. The amount procured by the Customer Renewable Supply Procurement Program will remain at 1000 megawatts with the additional 500 megawatts going to the retail customers. Each of the two proposed Requests for Proposals ("RFP") will increase by 250 megawatts.

3.

Paragraph 5 of the Stipulation discusses an RFP concerning distributed generation which reads in part:

> *The Company shall issue an RFP to procure energy from up to 150 MW AC of distributed generation solar resources ("DG") greater than 1 kW but not more than 3 MW AC.*[9]

The Commission finds that the amount of the distributed generation (DG) procurement shall be increased to 210 megawatt alternating current, which includes 160 megawatts of DG Requests for Proposal and a 50 megawatt customer-sited DG program. The Commission concludes that it is appropriate that projects for the customer-sited program shall be greater than one kilowatt but not more than three megawatts. Procurement shall be done through an application process, and if oversubscribed, a lottery shall be conducted. The Commission has determined that the customer-sited projects shall be paid avoided costs as calculated by the Renewable Cost Benefit Framework.

4.

The Commission recognizes the benefits of biomass as a renewable resource and finds and concludes that increased inclusion should be considered in the future development of the Company's Integrated Resource Plan. Noting that, the Commission directs the Company and Staff to work together on a proposal to procure an additional 50 megawatts of new biomass

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[9] Stipulation - Supply Side Plan, p. 3.

generation to serve Georgia Power's customers. This generation will utilize the competitive solicitation model that allows the Company to recover all of its program costs and grants the Company an additional sum.

The Company and Staff are directed to return to this Commission no later than the end of second quarter 2020 with a proposed biomass procurement strategy for the Commission's consideration and approval.

5.

The Commission finds that it is reasonable and appropriate to further advance the educational feature of integrated resource planning going forward. Therefore, the Commission concludes that the education initiative, Learning Power[10] budget shall be increased to $4 million annually for 2020 through 2022.

6.

The Commission finds and concludes that the record reflects the necessity and need for further development for energy storage capability. Further, witness's testimony noted that the cost associated with battery technology continues to decline. (Tr. Pp. 2448, 2792) Therefore, the Commission directs Georgia Power to develop a pilot project utilizing used lithium ion batteries for a grid-connected charging system for electric vehicles. The goal for the pilot shall include keeping charging of clean electric vehicles affordable and insulating the grid from spikes in electricity demand. The cost of the pilot shall not exceed $250,000. Georgia Power shall work with the Staff in designing the project to ensure that the project has a public benefit.

7.

[10] Stipulation – Demand Side Plan, Paragraph 11, p.10.

The Commission finds that the record in this proceeding established that the Automated Benchmarking Tool ("ABT") provides current value to customers and that demand for the ABT will continue to grow. The Commission directs Georgia Power to continue making the ABT available in the same manner for the next three years.

8.

With respect to Energy Efficiency, the Commission finds and concludes that the energy saving targets for the Company's residential and commercial energy efficiency programs be increased by 15 percent and the relative program budgets be increased by 10 percent. The Commission staff and the Company shall meet within 60 days of the Final Order to finalize the revised DSM portfolio and the DSM budgets for 2020 through 2022, which should include a projected 15 percent increase in savings.

9.

The record in this case identifies potential concerns with Georgia Power's current avoided cost calculation. The Company's obligation to determine the underlying avoided cost is imposed on the Company by the Public Utility Regulatory Policy Act (PURPA), a federal law. The Company proposed the RCB framework to identify additional cost savings resulting from the deployment of renewable generation resources in the 2016 IRP, and it was adopted by this Commission. PURPA's calculation of the Company's underlying avoided costs, and RCB's calculation of additional cost savings resulting from deployment of renewables, particularly distributed solar generation, seek different objectives and utilize different calculations. But together, PURPA and RCB are the building blocks used by the Company to set compensation rates for distributed solar generation.

The Commission is compelled by the testimony that highlighted the fact that, although the Company makes an annual filing of its avoided cost under PURPA, which are subject to the Commission's review, the methodology has not been the subject of a full review in twenty-five (25) years. The Commission finds and concludes that these concerns should be addressed shortly after the conclusion of Docket No. 42516, the 2019 Rate Case, through the Commission re-opening a proceeding in Docket No. 4822 to ensure appropriate valuation of renewable and demand-side resources. PIA Staff is directed to initiate a review of the Company's methodology and computation of avoided cost under PURPA.

10.

The Commission finds and concludes that the remaining provisions of the agreement shall have full force and effect as stated in the Stipulation and concludes that all other recommendations and requests from the Non-signing parties are denied.

******

ORDERING PARAGRAPHS

WHEREFORE, IT IS ORDERED, that the Commission adopts the Stipulation (Attachment A) as amended herein as a fair and reasonable resolution of the issues in Docket Nos. 42310 and 42311.

ORDERED FURTHER, that the amount of the utility scale renewable procurement shall increase to 2000 megawatts alternating current. The amount procured by the Customer Renewable Supply Procurement Program shall remain at 1000 megawatts with the additional 500 megawatts going to the retail customers. Each of the two proposed Requests for Proposals ("RFP") shall increase by 250 megawatts.

ORDERED FURTHER, that the amount of the distributed generation procurement shall increase to 210 megawatt alternating current, which includes 160 megawatts of DG Requests for Proposal and a 50 megawatt customer-sited DG program. The customer-sited program shall be greater than one kilowatt but not more than three megawatts. Procurement shall be done through an application process, and if oversubscribed, a lottery shall be conducted. The customer-sited projects shall be paid avoided costs as calculated by the Renewable Cost Benefit Framework.

ORDERED FURTHER, that the Company and Commission staff shall work together on a proposal to procure an additional 50 megawatts of new biomass generation to serve Georgia Power's customers. This generation shall utilize the competitive solicitation model that allows the Company to recover all of its program costs and grants the Company an additional sum. The Company and Commission staff shall come back to this Commission by no later than the end of second quarter 2020 with a proposed biomass procurement strategy for the Commission's consideration and approval.

ORDERED FURTHER, that the education initiative, Learning Power, budget shall be increased to $4 million annually for 2020 through 2022.

ORDERED FURTHER, that Georgia Power shall develop a pilot project utilizing used lithium ion batteries for a grid-connected charging system for electric vehicles. The goal for the pilot shall include keeping charging of clean electric vehicles affordable and insulating the grid from spikes in electricity demand. The cost of the pilot shall not exceed $250,000. Georgia Power shall work with the Commission staff in designing the project to ensure that the project has a public benefit.

ORDERED FURTHER, that the Company's Automated Benchmarking Tool ("ABT") shall be continued for the next three years.

ORDERED FURTHER, that the energy saving targets for the Company's residential and commercial energy efficiency programs shall be increased by 15 percent and the relative program budgets shall be increased by 10 percent. The Commission staff and the Company shall meet within 60 days of the issuance of this Order to finalize the revised DSM portfolio and the DSM budgets for 2020 through 2022, which must include a projected 15 percent increase in savings.

ORDERED FURTHER, that shortly after the conclusion of the 2019 Rate Case, Docket No. 42516, the PIA Staff shall initiate a review of the Company's methodology and computation of avoided cost in Docket No. 4822 pursuant to the Public Utility Regulatory Policy Act of 1978 to ensure appropriate valuation of renewable and demand-side resources.

ORDERED FURTHER, the Commission finds that remaining provisions of the agreement shall have full force and effect as stated in the Stipulation.

ORDERED FURTHER, that with the exception of the above findings of facts and conclusions of law, the Commission denies the remaining recommendations of all non-signing parties.

ORDERED FURTHER, all findings, conclusions, and decisions contained within the preceding sections of this Order are hereby adopted as findings of fact, conclusions of law, and decisions of regulatory policy of this Commission.

ORDERED FURTHER, that a motion for reconsideration, rehearing, oral argument, or any other motion shall not stay the effective date of this Order, unless otherwise ordered by the Commission.

ORDERED FURTHER, that jurisdiction over this matter is expressly retained for the purpose of entering such further Order(s) as this Commission may deem just and proper.

I/A

The above by action of the Commission in Administrative Session on the 16 day of July 2019.

Reece McAlister Executive Secretary	Lauren "Bubba" McDonald Chairman
7-29-19 Date	7/29/19 Date

I/A

DEBORAH K. FLANNAGAN
EXECUTIVE DIRECTOR

REECE McALISTER
EXECUTIVE SECRETARY

Georgia Public Service Commission

(404) 656-4501
(800) 282-5813

244 WASHINGTON STREET, SW
ATLANTA, GEORGIA 30334-5701

FAX: (404) 656-2341
www.psc.state.ga.us

June 6, 2019

Mr. Reece McAlister
Executive Secretary
Georgia Public Service Commission
244 Washington Street, S.W.
Atlanta, GA 30334

RE: Docket No. 42310 & Docket No. 42311 / Georgia Power Company's 2019 Integrated Resource Plan and Georgia Power Company's 2019 Demand Side Management

Dear Mr. McAlister:

Enclosed for filing please find a Stipulation executed on behalf of the Georgia Public Service Commission Public Interest Advocacy Staff and Georgia Power Company.

We have furnished an electronic and/or a copy by mail of this filing to all parties in this docket.

Sincerely,

Preston Thomas
Attorney

STATE OF GEORGIA

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

In Re:

Georgia Power Company's	)	
2019 Integrated Resource Plan and	)	
Application for Certification of Capacity	)	**Docket No. 42310**
From Plant Scherer Unit 3 and Plant	)	
Goat Rock Units 9-12 and Application	)	
for Decertification of Plant Hammond	)	
Units 1-4, Plant McIntosh Unit 1, Plant	)	
Langdale Units 5-6, Plant Riverview	)	
Units 1-2, and Plant Estatoah Unit 1	)	

In the Matter of:

Georgia Power Company's	)	**Docket No. 42311**
Application for the Certification,	)	
Decertification, and Amended	)	
Demand Side Plan	)	

<u>Stipulation</u>

The Georgia Public Service Commission (the "Commission") Public Interest Advocacy Staff ("PIA Staff"), Georgia Power Company ("Georgia Power" or the "Company") and the undersigned intervenors (collectively the "Stipulating Parties") agree to the following stipulation as a resolution of the above-styled proceedings to consider the Company's 2019 Integrated Resource Plan (the "2019 IRP") and Application for the Certification, Decertification, and Amended Demand Side Management Plan (the "2019 DSM Plan"). The Stipulation is intended to resolve all of the issues in these Dockets. The Stipulating Parties agree as follows:

<u>Supply Side Plan</u>

1. The 2019 IRP is approved as amended by this Stipulation.

2. Plant Hammond Units 1-4, Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6, and Plant Riverview Units 1-2 shall be decertified and retired as provided for in the 2019 IRP.

3. The Company shall procure 1,500 MW alternating current ("AC") of new utility scale renewable resources, defined as projects greater than 3 MW AC. 500 MW of these new resources shall be dedicated to all retail customers. The Customer Renewable Supply Procurement Program ("CRSP") is approved and shall be increased such that it will procure energy from 1,000 MW (600 MW of utility scale renewable resources for subscription by existing CRSP eligible customers, and 400 MW for subscription by CRSP eligible customers adding new load). The Utility scale procurement shall take place through two separate Requests For Proposals ("RFP"). The first RFP is expected to be issued in 2020 and will seek 250 MW of renewables with in-service dates of 2022 and 2023 for all retail customers, 300 MW for subscription by existing CRSP eligible customers, and up to 400 MW for subscription by CRSP eligible customers adding new load. The second RFP is expected to be issued in 2021 and will seek 250 MW of renewables with in-service dates of 2023 and 2024 for all retail customers, 300 MW for subscription by existing CRSP eligible customers and 0 to 400 MW for subscription by CRSP eligible customers adding new load (0 MW to 400 MW represents the remainder of any resources not procured for subscription by CRSP eligible customers adding new load in the first RFP). Any capacity for new load that remains unsubscribed at the end of the second RFP would be offered to any existing CRSP eligible customers whose Notice of Intent ("NOI") capacity request had not been fully met. Any remaining amounts procured through the RFPs for CRSP but unsubscribed by CRSP participants will be used to serve all retail customers.

All revenues collected through CRSP program, with the exception of the additional sum as described in Paragraph 7, and all appropriate costs, that are not being recovered elsewhere by the Company, incurred for CRSP procurement shall be included in the fuel clause and recovered through Fuel Cost Recovery mechanism ("FCR"). The CRSP costs and revenues to be included in FCR includes, but are not limited to, the costs to implement and administer the CRSP, the bid fees collected, the NOI Fees collected, and the cost of purchase power agreements ("PPA") executed through the CRSP program including any payments for PPAs made by participants. All revenues collected, and all appropriate costs, not being recovered elsewhere by the Company, incurred for the 500 MW of utility scale procurements for all customers shall be included in the fuel clause and recovered through FCR.

4. Within 60 days of the Final Order the PIA Staff and the Company shall begin to meet to develop the specific guidelines and NOI requirements for the CRSP Program. The proposed guidelines will be submitted to the Commission for

approval.

5. The Company shall issue an RFP to procure energy from up to 150 MW AC of distributed generation solar resources ("DG") greater than 1kW but not more than 3 MW AC. The projects must be at or below the Company's projected avoided costs. Contract terms will be up to 30 years. DG projects must interconnect to Georgia Power's distribution system. Bid fees will be set to recover the total cost of procurement for the solicitation. All revenues collected, and all appropriate costs not being recovered elsewhere by the Company incurred for DG procurements shall be included in the fuel clause and recovered through FCR.

6. The Renewable Cost Benefit Framework ("RCB") shall be utilized in the evaluation of bids received through the utility scale and DG RFPs. The PIA Staff has raised specific issues regarding the RCB components of Deferred Generation Capacity, Generation Remix, and Support Capacity and recommended that solar plus storage be considered its own technology using the RCB Framework. The Company and PIA Staff will work collaboratively to resolve the concerns raised by PIA Staff in this case. The Company and PIA Staff will meet within four months of issuance of Final Order in this case and make a good faith effort to resolve the issues. If the issues have not been resolved within this time, the Company and PIA Staff will work to resolve the issues before the next IRP. PIA Staff and the Company also understand that resolution of these issues does not limit the positions that either Party can take regarding the RCB in a future proceeding where modifications to the RCB may be considered. Until such time as these issues are resolved, the RCB used in evaluations will be based on the RCB components and methodologies as filed in the IRP using updated B2019 assumptions (or for later solicitations the applicable vintage assumptions) and calculations of deferred capacity value for the RCB will be based on the B2018 CWFT using the summer TRM of 16.25% as shown in Table B.1 of the January 2019 Reserve Margin Study.

7. The Additional Sum for utility scale resources procured pursuant to Paragraph 3 above and the DG resources in Paragraph 5 shall be set at 8.5% of the projected net benefits. This amount shall be levelized and recovered annually for the term of the PPA.

8. The use of seasonal planning by the Company to provide greater visibility into both summer and winter capacity needs is approved. In the event winter system conditions result in the need for transmission system assessments, the Company would incorporate applicable winter assessment results into future filings of

Technical Appendix Volume 3.

9. The Company and PIA Staff recognize that the use of a winter target reserve margin ("TRM") is necessary to effectuate seasonal planning as approved by this Stipulation. In the absence of a Commission approved winter TRM, the Company will use the System winter TRM for seasonal planning until such time as a winter TRM is agreed to between Staff and the Company and approved by the Commission. There is no requirement for the Commission to act upon the winter TRM until such time as one is approved. The Company may propose resource additions, if needed, to meet winter TRM, and the Commission can determine at that time what the appropriate winter TRM is and whether such additional capacity is needed. Stipulating Parties further agree that the Company may propose the adoption of a specific winter TRM in a future IRP proceeding or IRP update. The Company and PIA Staff will meet within six months of issuance of Final Order in this case to discuss these issues and will work to address the issues before the next IRP.

10. The Stipulating Parties agree that the Scherer Unit 3 Capacity offer should be rejected by the Commission. The offer by the Company, and the rejection by the Commission fulfills the Company's requirements under Docket No. 26550 to offer this capacity to the retail jurisdiction. The Company may, at its own discretion, offer such capacity in the wholesale market or to the retail jurisdiction in a future capacity solicitation or through other permissible vehicles.

11. The Company shall initiate a 2022-2023 and a 2026-2028 capacity-based RFP. The RFPs will be structured to address the capacity needs being sought and will require a level of capacity firmness and dispatchability that will be developed in conjunction with Commission Staff and the IE during the RFP development process. Specific RFP guidelines including resource eligibility requirements, updated IRP assumptions, and evaluation methodology and criteria will be approved by the Commission in accordance with the Commission's proscribed RFP process and may accommodate bids from renewable resources paired with storage. The Company agrees to include language in such RFPs that permit the Company to reject all bids at its discretion.

12. The parties acknowledge that should the retirement of Plant Bowen Units 1 and 2 be necessary there will be transmission issues that need to be addressed in the 2019 base rate case. However, the parties have not agreed on the best solutions to those issue. The Company will explore both traditional transmission solutions and alternatives to traditional transmission solutions (non-wire solutions) and

compare the costs of each approach.

13. The Company agrees to limit capital expenditures specific to Plant Bowen Units 1 and 2 through July 31, 2022. The capital expenditures approved in this paragraph are intended to allow for safe and reliable operations of the units. The Company agrees to annual limits on capital expenditures of $19 Million per year, or $57 Million for the three-year period ending July 31, 2022. The Company agrees to provide a justification to Staff for expenditures that may be needed to maintain safe and reliable operation of Bowen 1 and 2 that exceed the limits provided for in this Paragraph. Within 60 days of the final order in this case, Staff and the Company will meet to develop reporting requirements.

14. The certification of the upgrade to the Goat Rock Hydro-electric facility Units 9-12 is not approved at this time. The Stipulating Parties agree to modifications to the Company's plans to modernize its hydro-electric fleet so that such efforts focus upon five modernization projects. The projects are Terrora, Tugalo, Bartlett's Ferry, Nacoochee, and Oliver. The Company and PIA Staff agree to work together to determine the appropriate information sharing process to allow the Commission to monitor the Company's modernization efforts.

15. The Company is granted authority in this IRP to develop, own and operate energy storage demonstration projects totaling up to 80 MW. The Company will procure the batteries for its ownership through a competitive RFP process. The company will competitively solicit Engineering Procurement and Construction services and shall include the option of turnkey proposals as well. The Company will be required to file a plan with the Commission before undertaking construction and procurement of each project being proposed. In such filing the Company will provide the objectives of the project, location of the project, transmission evaluation of the project and detailed operating and testing plans. Commission Staff shall have 60 days to review the plans prior to Commission approval.

16. The Company's Environmental Compliance Strategy ("ECS") is approved. This includes specific approval of the Company's plans to address coal combustion residuals ("CCR") at the Company's ash ponds and landfills. Stipulating Parties acknowledge that projected CCR compliance cost have been reviewed in this case, but agree that it is not necessary for the Commission to approve a specific budget for CCR compliance in this IRP proceeding. The Parties agree that the Company will seek recovery of such costs in its 2019 base rate case. The PIA Staff reserves the right to challenge the Company's request in the 2019 base rate case, including, but not limited to, the period over which they

are recovered and the method by which they are recovered. To ensure the Commission is updated on CCR compliance efforts the Company will provide semi-annual reports to the Commission. The Company and Commission Staff will collaborate upon the schedule and content of such reports. The Company will also file the ECS annually with the Commission no later than March 31st of each year.

17. The detailed cost information that supports the measures taken to comply with the existing government imposed environmental mandates necessary for the Company to implement its environmental compliance plan as presented in Technical Appendix Volume 1 of the 2019 IRP, "Environmental Compliance Cost Recovery (ECCR) table" is acknowledged subject to the limits outlined in Paragraph 13 regarding Plant Bowen Units 1 and 2. Recovery of actual environmental compliance plan costs will be determined by the Commission in a rate case.

18. The remaining net book values of Plant Hammond Units 1-4, Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6, and Plant Riverview Unit 1-2 shall be reclassified as a regulatory asset and the Company shall continue to provide for amortization expense at the same rate as determined in the Company's 2013 base rate case. Timing of recovery of the remaining balance as of December 31, 2019 will be deferred for consideration in the Company's 2019 base rate case. The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the recovery mechanism and appropriate period in which the costs should be recovered if applicable. Parties may argue their respective positions on that issue in the 2019 base rate case.

Any unusable M&S inventory balance remaining at the date of the unit retirement shall be reclassified as a regulatory asset and the timing of recovery deferred for consideration in the Company's 2019 base rate case. The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the recovery mechanism and appropriate period in which the costs should be recovered if applicable. Parties may argue their respective positions on that issue in the 2019 base rate case.

19. Any over or under recovered cost of removal balances for each Retirement Unit shall be deferred for consideration until the Company's 2019 base rate case. The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the appropriate period in which the costs should be recovered. Parties may argue their respective positions on that issue in the 2019 base rate

case.

20. In Docket No. 36989 the Commission approved the donation of Kraft land to the Georgia Port Authority including approval of the accounting treatment for the donation proposed by Georgia Power. PIA Staff has raised a desire to propose alternative ratemaking treatment for the income tax benefits related to the Plant Kraft land donation. The Company believes the issue of the appropriate accounting treatment for the Kraft land donation is resolved per the Commission's Order in Docket No. 36989. To the extent PIA Staff disagrees, the Parties agree that any disagreement may be considered in the 2019 base rate case.

21. In the Commission's Final Order in Docket 40161 and 40162 the Commission authorized the Company to spend up to $99 million between now and the end of the second quarter of 2019 to investigate the option of pursuing new nuclear generation as a potential base load option at a site in Stewart County, Georgia. That Order further found that if the project was terminated, costs incurred toward that effort would be deferred for recovery to a regulatory asset and the timing of that recovery would be addressed in a future base rate case in which the Commission will determine the appropriate period to amortize the recovery of such costs. The Order also held that for ratemaking purposes, the Stewart County property shall continue to be categorized as Plant Held for Future Use. Nothing in this Stipulation is intended to limit the rights of PIA Staff or the Company to pursue their respective positions on cost recovery of Stewart County Site investigation cost.

22. When filing the 2022 IRP or when filing any updates to the IRP prior to the 2022 IRP filing, the Company agrees to provide the Commission Staff working copies of, or access to data used to develop charts, tables, and graphics contained in the filing; models (for example, transmission models, load forecast models, financial models and economic models), and results of relevant analyses performed in the development of that IRP. The models and analyses should be configured to replicate inputs used to derive results incorporated in its base case scenario, and this information shall be provided within 10 days after the IRP or update to the IRP is filed.

23. The Company will compute weather normalized peak demands for the winter and summer seasons of each historical year going forward starting in 2019.

24. The Company will investigate methodologies for allocating long-term annual energy sales for each class to monthly amounts to account for anticipated trends

in seasonal energy sales.

25. The Company agrees to file with the 2022 IRP a forecast scenario of Georgia Power's Peak and Energy forecast using data for the most recent 20 year normal weather.

26. In conjunction with the ongoing level of review and analysis required by this agreement, Georgia Power will agree to pay for any reasonably necessary specialized assistance to the Staff in an amount not to exceed $500,000 annually. This amount paid by Georgia Power under this paragraph shall be deemed as a necessary cost of providing service and the Company shall be entitled to recover the full amount of any costs charged to the utility.

27. Neither Staff nor the Company has recommended the Emory micro grid project. However, if the Commission decides that it is appropriate to move forward with the project, both the Staff and Company recommend that it be done so only on the condition that, if the project costs exceed the benefits to other ratepayers, Emory agrees to pay the difference.

Demand Side Plan

1. The Demand Side Plan is approved as amended by this Stipulation.

2. The Company and Staff shall collaborate to investigate methodologies to model DSM as an additional scenario in its supply side system planning tools as a part of its IRP development and resource optimization process where DSM will be modeled alongside traditional supply-side options. The company will produce a white paper and discuss its findings with the Staff nine months prior to the filing of the 2022 IRP.

3. Georgia Power and PIA Staff agree that calculations of the kWh and kW savings from the Company's certified DSM programs in 2023 be adjusted to actual savings once the Company has completed the impact and process evaluations for each certified DSM program and the Company and Staff reach agreement on evaluation impacts during 2021.

4. The Company and PIA Staff agree that the percentage increases in the current certified program budgets for non-incentive program costs per first-year kWh saved for the 2020 to 2022 period when compared to 2017 and 2018 actual spending on non-incentive costs per first-year kWh saved will be capped at no

more than a 50 percent increase. The 2020 to 2022 budgets for the Company's certified programs will be as presented in Staff Exhibits BSKA-8 and BCS-7. This agreement does not set a precedent for requested budget requests in future IRP cycles and only applies to 2020 through 2022 because implementation costs have the potential to change over time in future IRP cycles.

5. The Demand Side Management Working Group ("DSMWG") will continue in its present form and be involved in the development of future demand side management programs in the same manner as the DSMWG has operated in past IRP cycles.

6. For the Income-Qualified ("Crowd Funding") Program, the Company will maintain the current EASP participant cap of $3,750 per household, the Company will expand its potential crowd funding donation sources, and for the initial term of the Program the Company will not earn an Additional Sum on the savings realized by donations from individuals, non-profits, grants, companies, and partnerships. After the initial review of the Program, the Company may request an additional sum in the 2022 IRP for the Program.

7. The Company and PIA Staff agree to work together over the next nine-months to investigate the reduction of administrative costs for a potential Income Qualified Tariff Based Financing Pilot for 500 income qualified customers. The Company and Staff will also work together to set a policy for the collection of uncollectibles from a potential Income Qualified Pilot through the Residential DSM Tariff. The Company will file a more complete pilot plan with the Commission by April 1, 2020.

8. The Commercial Custom Program will include a per building cap of $75,000 in its final program plan.

9. Once a program implementer is selected and program plans are drafted, the program plans for all approved energy efficiency and demand response programs will be provided to Staff for review prior to the implementation of the programs. The Company should provide Staff up to 15 working days for review of the draft Final Program Plans. In order to deliver programs for customers on schedule, the Company will work with Staff to discuss and address potential concerns with final program plans without delaying program implementation schedules.

10. The current Commission policy that requires the Company to provide detailed evaluation plans for each of the approved DSM programs within 90 days of the selection of Program Implementers for each of the certified programs will

continue. However, the Staff will work with the Company to extend the 90 days on an as needed basis as it has in past IRP cycles.

11. The Education Initiative Learning Power budget will continue at $3 million annually for 2020 through 2022.

12. The Residential and Commercial Energy Efficiency Consumer Awareness annual budgets will continue at $4.5 million and $1.1 million, respectively.

13. The Company's pilot budget will be set at $3million annually and split between the Residential and Commercial classes. The Company will seek Staff's input before the start of any pilot. This pilot budget includes $400,000 in pilot evaluation costs.

14. The HopeWorks low income weatherization program budget will increase to $400,000 per year.

15. The Company will earn an Additional Sum for DSM programs according to the mechanism approved in the Commission's August 2, 2016 Final Order in Docket 40161 & 40162.

16. The Company agrees that all references to Non-Participant Spillover ("NPSO") will be removed from its program plans and will not be considered in future calculations of Additional Sum.

Agreed to this 6th day of June, 2019.

Preston Thomas

On Behalf of the Georgia Public Service Commission
Public Interest Advocacy Staff

Brandon F. Marzo

On Behalf of Georgia Power Company

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of	)	
	)	**Docket No. 42310**
Georgia Power Company's	)	
2019 Integrated Resource Plan	)	
	)	
Georgia Power Company's	)	**Docket No. 42311**
2019 Demand Side Management Plan	)	

CERTIFICATE OF SERVICE

I hereby certify that the foregoing **Stipulation** in the above-referenced docket was filed with the Commission's Executive Secretary, an electronic copy of same was served upon all parties and persons listed below via electronic mail, or unless otherwise indicated, as follows:

Reece McAlister*
Executive Secretary
Georgia Public Service Comm.
244 Washington Street, SW
Atlanta, GA 30334
reecem@psc.state.ga.us

Kyle Leach
Director, Regulatory Affairs
Georgia Power Company
Bin 10230
241 Ralph McGill Boulevard, NE
Atlanta, GA 30308-3374
kcleach@southernco.com

Kevin Greene, Esq.
Troutman Sanders
NationsBank Plaza
600 Peachtree Street, NE
Suite 5200
Atlanta, GA 30308
kevin.greene@troutmansanders.com

Bryan Jacob
Southern Alliance for Clean Energy
1455 Hampton Hill Drive
Alpharetta, GA 30022
bryan@cleanenergy.org

Robert B. Baker
Robert B. Baker, P.C.
2480 Briarcliff Road, N.E.
Suite 6
Atlanta, GA 30329
bobby@robertbbaker.com

Jeffry Pollock
J. Pollock Incorporated
12647 Olive Blvd., Suite 585
St. Louis, Missouri 63141
jcp@jpollockinc.com

G. L. Bowen, III
Charles B. Jones, III
Georgia Association of Manufacturers
The Hurt Building
50 Hurt Plaza, Suite 985
Atlanta, Georgia 30303
rbowen@gamfg.org
cjones@gamfg.org

Randall D. Quintrell
Randall D. Quintrell, P.C.
999 Peachtree Street, N.E., 23rd Floor
Atlanta, Georgia 30309-3996
randyquintrell@eversheds-sutherland.com

Bruce Bucat, Esq.
Mid-Atlantic Renewable Energy Coalition
29N. State Street, Suite 300
Dover, DE 19901
bburcat@marec.us

Liz Coyle
Georgia Watch
55 Marietta Street, NW
Suite 903
Atlanta, GA 30303
lcoyle@georgiawatch.org

Berneta L. Haynes, JD
Georgia Watch
55 Marietta Street, Suite 903
Atlanta, GA 30303
bhaynes@georgiawatch.org

Simon Mahan
Southern Renewable Energy Association
5120 Chessie Circle
Haltom City, TX 76137
simon@southernwind.org

Alan R. Jenkins
Jenkins at Law, LLC
2265 Roswell Road, Suite 100
Marietta, GA 30062
aj@jenkinsatlaw.com

Robert Jackson – Ga. Bar #387750
Robert B. Jackson, IV, LLC
260 Peachtree Street – Suite 2200
Atlanta, GA 30303
rbj4law@gmail.com

Kasey Sturm – Ga. Bar #690615
GREENLAW c/o K.A. Sturm
One Alliance Center 4th Floor
3500 Lenox Road
Atlanta, GA 30326
kaseys@weissman.law

Zachary M. Fabish, Esq.
The Sierra Club
50 F Street NW, 8th Floor
Washington, DC 20001
zachary.fabish@sierraclub.org

Ben J. Stockton, PE, MBA
Executive Director
Concerned Ratepayers of Georgia
2305 Global Forum Blvd, Suite 912
Atlanta, GA 30340
encomanager13@gmail.com

Steven C. Prenovitz, MBA
Consultant
Concerned Ratepayers of Georgia
4295 Amberglade Ct
Norcross, GA 30092
scprenovitz@gmail.com

Stephen E. O'Day
Vickie C. Rusek
Smith, Gambrell & Russell, LLP
1230 Peachtree Street NE, Suite 3100
Atlanta, GA 30309
soday@sgrlaw.com
vrusek@sgrlaw.com

Jim Clarkson
Resource Supply Management
135 Emerald Lake Rd
Columbia, SC 29209
jclarkson@rsmenergy.com

Newton M. Galloway
Terri M. Lyndall
Steven L. Jones
Galloway & Lyndall, LLP
The Lewis Mills House
406 north Hill Street
Griffin, GA 30223
ngalloway@gallyn-law.com
tlyndall@gallyn-law.com
sjones@gallyn-law.com

William Bradley Carver, Sr. Esq.
Hall Booth Smith, P.C.
191 Peachtree Street, NE – Suite 2900
Atlanta, GA 30303
bcarver@hallboothsmith.com

Kurt Ebersbach
Jullian Kysor
Stacy Shelton
Southern Environmental Law Center
Ten 10th Street NW, Suite 1050
Atlanta, GA 30309
kebersbach@selcga.org
jkysor@selcga.org
sshelton@selcga.org

Peter Hubbard
Georgia Center for Energy Solutions
55 Leslie Street, SE
Atlanta, GA 30317
peter@georgia-ces.org

Joe McDonough
Managing Partner
McFinney, LLC
P.O. Box 20569
St. Simons Island, GA 31522
joe@captjoe.com

Adrian L. Jackson
Associate General Counsel
Emory University
Office of the General Counsel
201 Dowman Drive
101 Administrative Building
Atlanta, GA 30322
adrian.jackson@emory.edu

William W. Maycock
R. Danielle Burnette
Smith, Gambrell & Russell, LLP
1230 Peachtree Street, N.E.
Suite 3100, Promenade
Atlanta, GA 30309
wmaycock@sgrlaw.com
dburnette@sgrlaw.com

So certified, this 6th day of May 2019.

Preston Thomas
Attorney