PROJECT NO. 49125

REVIEW OF ISSUES RELATING TO ELECTRIC VEHICLES	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

COMMENTS OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC

CenterPoint Energy Houston Electric, LLC ("CenterPoint Houston" or the "Company") appreciates the opportunity to respond to the Commission's questions and request for comments issued in this project on December 13, 2019. As shown in the Company's responses to the Commission's questions (below), it is reasonable to expect increases in both the number of electric vehicles ("EVs") and the number of EV charging stations in CenterPoint Houston's service area over the next ten years, which will likely necessitate increased capital spending by the Company to meet and effectively manage the increased demands on its system. However, the EV growth projections in the Company's responses vary widely and are based on numerous assumptions about future EV development.

In light of the uncertainty regarding the pace and impacts of future EV development, the Company recommends that the Commission allow utilities to begin implementing pilot programs now not only to identify and remove potential impediments to increased competitive market investments in the commercial EV charging stations that might be needed when EV penetration ramps up, but also to better anticipate the utility infrastructure impacts of having potentially ubiquitous private and commercial charging stations within their respective service territories. The pilot programs could help utilities better identify where EV charging station loads will be greatest and the prudent system upgrades needed to meet those loads. The pilot programs could also be useful for understanding consumer charging behavior to anticipate the effects of EV charging on system peaks and identifying best practices for managing those peaks.

The Commission should also support consumer awareness and education about the relationship between EVs and the electrical grid that will deliver power to, and receive power from, their EV batteries, by adopting rules or a policy that encourages utilities to implement such public awareness and education campaigns. In addition to promoting awareness and education, the Commission should also consider encouraging direct utility investment in public EV charging stations in areas where competitive market forces may not reach but where it may nonetheless be in the public interest for EV charging stations to exist, such as along hurricane evacuation routes and in economically depressed communities.

CenterPoint Houston is committed to investing in and managing its system to meet all these challenges and looks forward to working with the Commission and the other parties to this project to identify and develop the rule or policy changes necessary to be successful.

Respectfully submitted,

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ATTORNEY FOR CENTERPOINT
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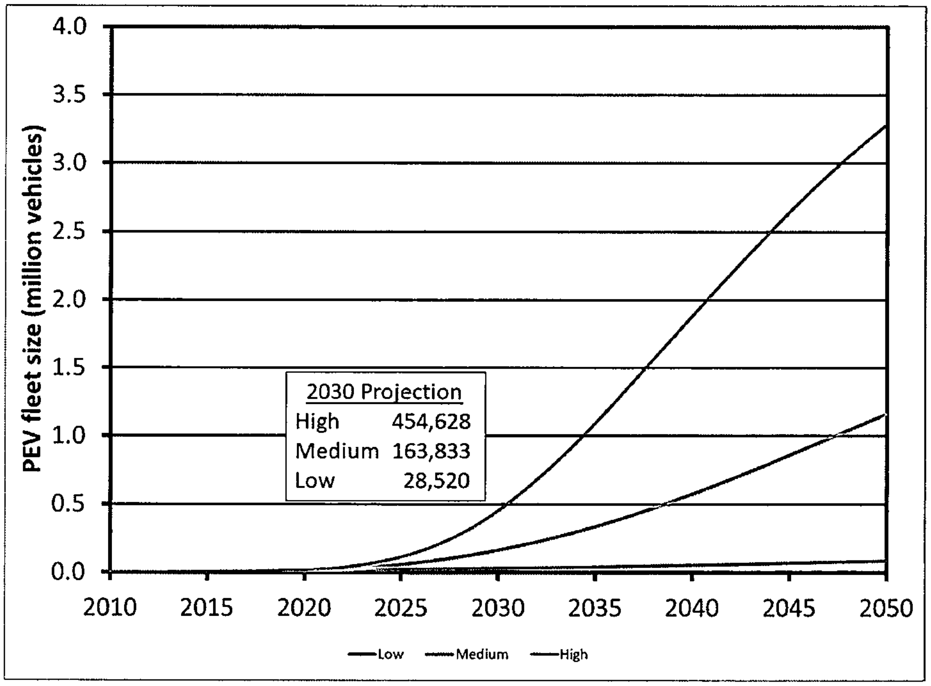
1. **The Commission requests that parties provide current data sources and projections for the expected deployment of electric vehicles in Texas over the next ten years. If available, sources should attribute the projections by vehicle (i.e., personal, commercial short-haul including fleets and buses, and commercial long-haul electric vehicles).**

Light-duty Electric Vehicle Projections - CenterPoint Energy Houston Electric Service Area



Light-duty Electric Vehicle Projection Scenarios for CenterPoint Houston. EPRI, Palo Alto, CA: 2020. Reprinted with permission of EPRI, (c) 2020.

The methodology for the above forecast is found in Attachment PUCT01-01. The forecast is dependent on available adoption incentives. Light-duty electric vehicles include passenger cars, minivans, pickups, SUVs and other 2-axle/4-tire trucks used for personal/commercial applications.

Attachment(s):
PUCT01-01 – EPRI Plug-in Electric Vehicle Market Projections.pdf

2. **Please provide any current data sources and information on the expected amount of new load attributable to electric vehicles over the next ten years. If available, the data sources should attribute this load by vehicle (i.e., personal, commercial short-haul including fleets and buses, and commercial long-haul electric vehicles).**

In 2014, Xcel Energy in Colorado initiated a pilot evaluation of personal Level 2 electric vehicle charging impacts on the grid. The small study of 20 participants identified an average monthly peak of 1.28kW and an average coincidental increase of peak demand of 0.28kW. See Attachment PUCT02-01 for additional information.

Additionally, in a 2019 filing by Dominion Energy in Virginia, a forecast of electric vehicle adoption used an average incremental load impact of 1.15kW. Extrapolating this data point over CenterPoint Houston's 2030 forecast in Question #1 yields a range of 33MW to 523MW.

ERCOT's 2018 LTSA Report includes some EV projection assumptions within its Emerging Technologies Scenario. See Table below extracted from this report and included as Attachment PUCT02-03.

Table 2: EV Penetration and Charging Demand Estimation for Emerging Technology Scenario

Type	Number of Vehicles in 2033	Per Vehicle Charging (kWh)	Peak Charging Demand (MW)
Cars	3,000,000	20	5,940
Short Haul/Buses	80,000	350	2,800
Long Haul Trucks	200,000	600	10,200

Attachment(s):
PUCT02-01 - CO-DSM-2014-EV-Pilot-Evaluation.pdf
PUCT02-02 – Dominion GTP Filing w EV Forecast.pdf
PUCT02-03 – 2018_ERCOT_LTSA_Report.pdf

Electric Vehicle Charging Station

Pilot Evaluation Report

May 2015

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Executive Summary

The Electric Vehicle Charging Station (EVCS) Pilot was implemented in 2013 and 2014 to help prepare for the arrival of mass market electric vehicles. The aim of the pilot was to gain understanding of:

- customer charging patterns and behaviors,
- how charging load coincides with Xcel Energy's Generation System (System) peak in Colorado,
- how technically and operationally feasible it is to interrupt vehicle charging through Demand Response (DR), and
- how vehicles may impact the distribution system.

Another key objective of the pilot was to establish technical assumptions and determine cost-effectiveness for the DR portion of the pilot in order to determine whether the pilot should be proposed as a DR program within Xcel Energy's Demand Side Management (DSM) program portfolio and offered to a larger group of customers.

Twenty Xcel Energy electric customers in Colorado were recruited to participate in the pilot through a combination of work with a third-party vendor (National Car Charging) and Xcel Energy marketing channels. Ten participants received a ChargePoint Level 2 (240 Volt) charging station and the other ten participants had a Consert load control device installed on their existing Level 2 charger. Along with the ability to keep the equipment after the conclusion of the pilot, the participants were given a $100 incentive for each year they agreed to participate in DR events. In exchange for this, Xcel Energy was able to monitor the daily usage of the charging stations, download the data, and control the charging up to twelve times per year.

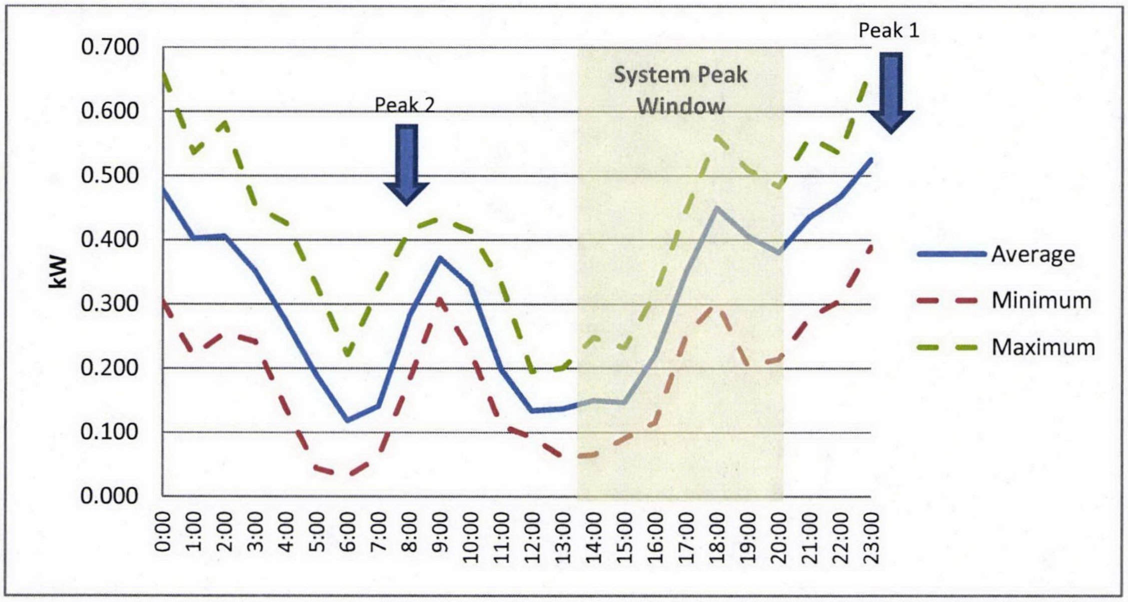
Electric Vehicle Charging Patterns

When reviewing the aggregated charging data of the group of 20 pilot participants, we see that customers charge their vehicles throughout the day, but two distinct peak periods are evident. The highest peak time is around 11:00 p.m., with a secondary peak around 9:00 a.m. This secondary peak is primarily driven by about 25% of the pilot participants who charge their vehicles in the morning vs. overnight.[1]

The resulting aggregated load profile of the pilot participants has a general shape that appears to be independent of the time of year (season) and time of week (weekday or weekend). However, when each participant is looked at as an individual there is noticeable variation hour-by-hour and month-by-month in the load levels.

[1] The morning peak has not been a characteristic of larger data sets and may be exaggerated in the results because of the small sample size. Non-Xcel Energy EV project data sets can be referenced at www theevproject.com/documents php.

Figure 1: EVCS Participants: 12-Month Load Profile



System Peak Impact

Results from the evaluation of the EVCS pilot indicate that there is minimal impact to System peak, in terms of additional load/potential DR savings, even as the kilowatt (kW) savings are projected across the estimated existing population of electric vehicles in Colorado. The average potential demand reduction (kW) per vehicle on the System peak day is approximately 0.28 kW. For comparison, the average demand of a typical household refrigerator is 0.19 kW.

Along with this low System peak impact is a load factor of 19.5% which means that EV charging is not constant.

Distribution System Impacts

An internal Xcel Energy study concluded that the Company is 10+ years away from seeing any significant impact to mainline distribution feeders, substation transformers, or distribution transformers from electric vehicles. The study also concluded:

- A 5% EV penetration rate (EVs per total number of residential customers) equates to 2%-4% additional substation transformer peak load.
- Distribution feeder capacity significance starts around a 4% EV penetration rate and equates to a 2%-4% demand growth per feeder.
- At a 5% EV penetration rate across the residential customer segment, potentially 4% of the distribution transformer population serving residential customers could be overloaded if charging is aligned with peak load times.
- Distribution transformer loading will be of most concern when there are two or more EVs served off the same transformer.

Data analysis from the pilot showed that 86% of the time EVs are not charging at all and there was a wide variance in when charging took place.

Customer Comments and Feedback

Approximately half of the pilot participants owned their EV, and the other half leased them. Around half of the group expected to keep their EV for another 1-3 years and another third of the participants expected to keep their EV for less than a year.

The pilot participants were happy overall with the pilot believing that communication was at an appropriate level and 12 control events per season were reasonable. Most were either not inconvenienced, or mildly inconvenienced, by the control events and felt that a yearly incentive of $100 was sufficient.

A group of non-pilot participant EV owners was also surveyed and, along with the pilot participants, most charged their vehicle at home most of the time, with many not able to charge their vehicle at work. About half of EV drivers are using the higher voltage Level 2 (240 Volt) charger.

EV owners are an engaged group of customers and there is a high willingness to participate in future EV-related pilots with the primary motivation being no up-front equipment costs (i.e. utility pays for any incremental equipment needed to participate).

Other Key Learnings

- Controlling EV charging is technically feasible
- The pilot group had slightly lower charging peaks in summer than winter
- Customers have shown interest in an off-peak EV rate
- EV owners are also very interested in renewable energy

If System impacts become more significant there are several mitigation opportunities utilities might consider. Such opportunities could include rates that encourage off-peak EV charging or advanced load control programs that optimize customer charging needs with System costs.

Electric Vehicle Charging Station (EVCS) Pilot

Background

In 2011, Xcel Energy expected to see mass market electric vehicles (EV) delivered in Colorado starting in 2012. To better understand the impact of this market, Xcel Energy implemented an Electric Vehicle Charging Station (EVCS) Pilot. This pilot was launched via the 60-Day Notice in late 2011.

The pilot was to provide monitoring and demand response (DR) results for three years from the DR event season of 2012 through the DR event season of 2014. However, based on performance of vendor equipment during 2012, the scope was changed and recruiting participants started in Q2-2013; therefore customer equipment monitoring and controlling did not commence until August 2013.

Objectives

The main objectives of the pilot were to determine when customers are charging, the typical duration of the charge, and frequency by which the charging load is available for Demand Response. Other objectives included analyzing the demand savings, establishing technical assumptions and determining cost-effectiveness. These things, along with customer acceptance, were undertaken to determine whether an electric vehicle DR program should be offered to a wider set of customers.

Original research to be addressed by this pilot included:

- Monitoring residential and commercial[2] charging characteristics and behaviors
- Identifying if the vehicle charging overlapped with the System peak
- Distinguishing a potential strategy for controlling vehicle charging that would minimize the impact to the distribution system

Evaluation Plan

Evaluation of demand data was one of the key outcomes for the pilot. Charging data for all participants and control periods was analyzed to understand what a "typical" charging curve looks like for an average participant, the average over the population, and the average per type of vehicle. This information was used to determine the coincidence factor associated with controlling a residential EV charger. All participants were controlled and monitored via a two-way communication capable DR control device. Along with controlling load, the DR device had the capability of recording data every 15 minutes. The DR device recorded the following data: date and time, kilowatts, volts, amps, kilowatt-hours, frequency, and charging events. Data retrieval from all participants occurred on a daily basis. In order to simulate a DR event, up to twelve 4- to 6-hour duration control events during each summer peaking season were dispatched to determine peak demand (kW), charging demand (kW) curves, coincidence to System peak, and duration of charging periods.

Pilot Description

The pilot's original design called for a direct load control switch to be installed adjacent to an EV charging station to monitor and control the customer's vehicle charging. The switch selected for the

[2] While commercial charging characteristics were proposed for the original pilot, the scope was scaled down to only focus on residential EV charging.

pilot was similar to devices used for the Company's Saver's Switch product, which provide direct load control on central air conditioners. However, the EV pilot switch was also slated to provide two-way communication and monitoring capabilities. Due to poor functionality, installation difficulties, and higher than anticipated costs with this approach, the pilot was redesigned at the end of 2012. The Company wanted to ensure the best experience for pilot participants and potential future program participants.

Phase 1 of the redesigned pilot was aimed at finding an existing charging system that already had load control capability, two-way communication, and load monitoring built in, so that the Company could readily start calling DR events for the 2013 control season. Simultaneously, research was done to find another switch/controller that met the requirements of the original filed pilot design. Once the new device was identified, it was added as Phase 2 of the pilot. Along with hardware installations, the pilot team decided to explore the potential for partnering with an automotive manufacturer on a software-based solution for controlling EV chargers. This was defined as Phase 3 of the pilot.

Phase 1: Test of EV Charging Stations

Phase 1 involved deployment of ten market-tested EV charging stations. Although this solution went beyond what would be deployed in an EV program, as it included a Level 2 charging station along with the controller, the units had all the capabilities desired from a load control device and were available for immediate deployment. A third-party reseller was engaged to manage the end-to-end deployment, from customer recruiting, device procurement, and post-sale support. The ChargePoint system—the selected charging station—included a robust reporting system with an appealing design and user interface. The pilot participants purchased these systems directly from the reseller at a reduced price and subsidized by Xcel Energy.

Phase 2: Test of Charge Controller on Existing Level 2 Chargers

While Phase 1 was being deployed and initial data was collected, the pilot team searched to find a load control device which provided the functionality originally desired at a price point in line with budget estimates. A suitable solution, a controller from Consert, was found and ten load control devices were deployed on existing Level 2 EV chargers as was originally envisioned for the pilot. An independent electrician was hired to manage the installation of the equipment. Unfortunately, the device was not available from the manufacturer until the second quarter of 2013, delaying customer deployment and installation.

Phase 3: Test of Onboard Vehicle Capabilities

Work in re-scoping the pilot drove to the conclusion that the ultimate load control solution for EVs may involve direct interaction with the vehicles themselves. To this end, a third phase was added to engage vehicle manufacturers and determine how Xcel Energy could leverage on-board charge control technology. The goal was to validate the ability to leverage this technology in lieu of deploying separate load control devices to control/interrupt the charging. Conversations with various manufacturers led to serious discussion with GM OnStar and a project proposal was submitted to them in July 2013.

During demand response events Xcel Energy interrupted participants' charging devices no more than 12 times per control season. For their participation, customers were given an annual credit of $100 and access to the associated data related to the vehicle charging.

To assess Phases 1 and 2 of the pilot, daily load data was tracked and recorded starting in March 2013 through December 2014 once equipment was installed and operational. Phase 3 efforts were disbanded in August 2014 due to an inability to reach a mutually acceptable agreement with OnStar.

Target Market

The primary target market for this pilot was 20 customers who currently own EVs and, in the case of the Phase 2 test, already had a Level 2 charger installed.

Participants in Phase 1 were acquired by the marketing efforts of a third-party reseller managing the end-to-end deployment. Participants were individuals who were owning/leasing EVs and in the market for a Level 2 charging station. Charging stations were provided to participants on a "first come, first served" basis.

Phase 2 participants were recruited via e-mail and direct mail targeting Public Service customers who had purchased/leased a qualifying EV according to the Electric Vehicle Information Exchange (EVIX) listings. Participation was, similar to Phase 1, available to eligible customers on a "first come, first served" basis.

Technology/Equipment

The EVCS Pilot design originally involved working with a load control device from Canon, similar to the device used for the Saver's Switch (A/C load control) program. Upon initial deployment of the selected load control device in 2012, key issues were identified which impacted the filed budget and scope of the pilot.

- Actual costs associated with the load control devices were greater than the initial vendor quote.
- The customer experience associated with the equipment selected for the test was not at an acceptable level.
    - The device lacked an "OEM look/feel," thus presenting a poor customer experience.
    - Charging data within the customer portal was reported in Amps. Conversion to kWh was possible, but at a notable cost to the pilot.

Due to these challenges, the pilot was re-scoped, new vendors were investigated, the new scope was tested, the budget updated, and new devices were deployed starting in 2013.

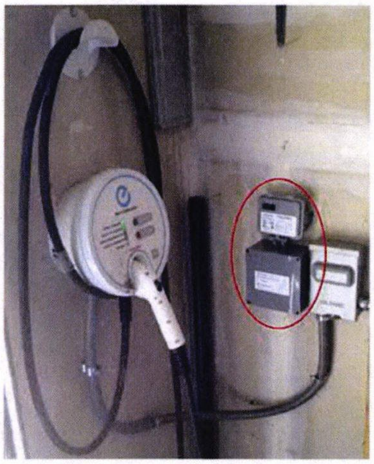
Phase 1

Phase 1 recruiting started in the second quarter of 2013 and included the installation of Level 2 (240 Volt) ChargePoint charging stations in ten participating customer's homes. This process was managed by a local ChargePoint subcontractor. ChargePoint provided a web portal to access the 15-minute interval load data. The web portal was only available for access by Xcel Energy, not the pilot participants. Following completion of the pilot the customer was able to keep the charging station.

ChargePoint Model CT-

chargepoint

Phase 2



Phase 2 recruiting began in at the end of the 2nd quarter of 2013. This solution provides those customers currently owning a Level 2 (240 Volt) charging station with a load control device provided by the company Consert. The device was installed in the customer's home free of charge. As with Phase I, the customers received a $100 credit on their bill for participation in the pilot. Customer recruiting for this effort was managed internally by the Company. Interval load data was collected at 5-minute intervals each day and was available for download from Consert's secure FTP site the following day. The pilot participants were able to view their daily usage at the Consert web portal.

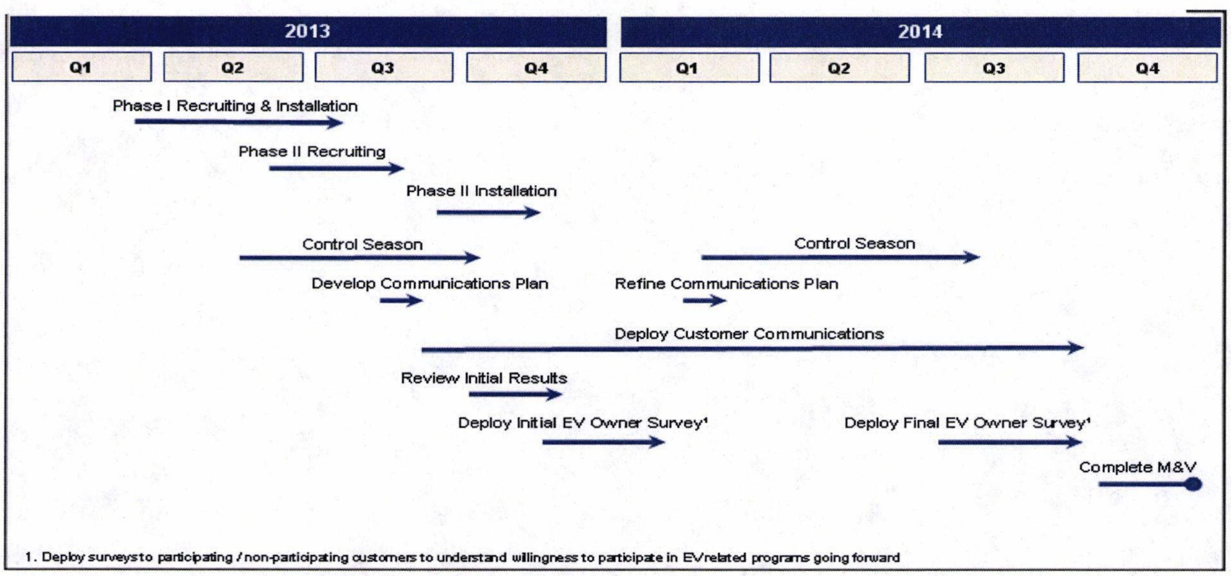
Phase 3

Phase 3 of the EVCS Pilot was designed to understand the ability to leverage OEM's onboard capabilities (e.g. General Motor's OnStar®, Nissan's CarWings™ and Ford's SYNC™) as a load control solution. Initial research determined that OnStar was the only manufacturer with the capability to support demand response related actions via telematics (at the time). Other OEM's were hesitant to engage in discussions on this.

Timeline

The following chart illustrates the planned timeline of the pilot:

Figure 2: Pilot Timeline



Data Used for Analysis

The majority of pilot analysis utilized the daily load data collected for each participant. Information from the DR events also provided insight on impact to the customer and Xcel Energy's System.

Daily Load Data

Daily load data was tracked for all participants in the pilot. The 15-minute interval load data from ChargePoint data and 5-minute interval load data from Consert was collected from March 2013 through December 2014. The data was then compiled into hourly averages by Xcel Energy's Load Analysis staff to determine the load profile and peak load impact.

Demand Response Events

In 2013, DR events were scheduled for four hours between 2:00 p.m. and 6:00 p.m. for both Phase 1 & 2 participants. Since the daily load data was indicating that most participants didn't charge their vehicles during this time, the event period was extended in 2014 to six hours (between 2:00 p.m. and 8:00 p.m.).

Originally, the DR events were meant to align with peak load days on the Xcel Energy System and only interrupt on days where the temperature was forecasted to be above 95°F (considered System peak conditions). June and July of 2014 passed with no forecasted 95°F days,[3] so in order to ensure an adequate number of test days, the temperature threshold was reduced to 90°F and DR events recommenced in August 2014.

Also of note, the Consert system would only allow 4-hour control windows. The vendor was notified of this; however, there was no plan to change this in their software. So, an attempt was made to schedule two consecutive events to cover the 2:00 – 8:00 p.m. window

The following is a summary of the DR events that were implemented in 2013 and 2014:

Phase 1: ChargePoint

In 2013, the control event periods were scheduled from 2:00 – 6:00 p.m. In 2014, the control event periods were extended an additional two hours from 2:00 – 8:00 p.m. The shaded dates on the calendar indicate ChargePoint control event days.

June 2013						
S	M	T	W	T	F	S
						1
2	3	4	5	6	7	8
9	10	11	12	13	14	15
16	17	18	19	20	21	22
23	24	25	26	27	28	29

July 2013						
S	M	T	W	T	F	S
	1	2	3	4	5	6
7	8	9	10	11	12	13
14	15	16	17	18	19	20
21	22	23	24	25	26	27
28	29	30	31			

August 2013						
S	M	T	W	T	F	S
				1	2	3
4	5	6	7	8	9	10
11	12	13	14	15	16	17
18	19	20	21	22	23	24
25	26	27	28	29	30	31

[3] Control events were planned on a day-ahead weather forecast developed by in-house meteorologists using NOAA data.

August 2014						
S	M	T	W	T	F	S
					1	2
3	4	5	6	7	8	9
10	11	12	13	14	15	16
17	18	19	20	21	22	23
24	25	26	27	28	29	30
31						

September 2014						
S	M	T	W	T	F	S
	1	2	3	4	5	6
7	8	9	10	11	12	13
14	15	16	17	18	19	20
21	22	23	24	25	26	27
28	29	30				

Phase 2: Consert

In 2013, control events were generally scheduled from 2:00 – 6:00 p.m., with the exception of 2:00 – 4:00 p.m. on 8/21/2013. In 2014, most control events were scheduled from 4:00 – 8:00 p.m. as the Consert system only allowed a maximum of 4-hour control periods. Work-arounds were used for 8/5/2014 and 9/26/2014 to attempt to cover the entire 2:00 – 8:00 p.m. time period. It was recommended to Consert that future software updates allow any length of control period. The shaded dates on the calendar indicate Consert control event days.

August 2013						
S	M	T	W	T	F	S
				1	2	3
4	5	6	7	8	9	10
11	12	13	14	15	16	17
18	19	20	21	22	23	24
25	26	27	28	29	30	31

September 2013						
S	M	T	W	T	F	S
1	2	3	4	5	6	7
8	9	10	11	12	13	14
15	16	17	18	19	20	21
22	23	24	25	26	27	28
29	30					

October 2013						
S	M	T	W	T	F	S
		1	2	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
20	21	22	23	24	25	26
27	28	29	30	31		

August 2014						
S	M	T	W	T	F	S
					1	2
3	4	5	6	7	8	9
10	11	12	13	14	15	16
17	18	19	20	21	22	23
24	25	26	27	28	29	30
31						

September 2014						
S	M	T	W	T	F	S
	1	2	3	4	5	6
7	8	9	10	11	12	13
14	15	16	17	18	19	20
21	22	23	24	25	26	27
28	29	30				

Analysis & Results

Measurement of available DR was one of the key outcomes of the pilot. Charging data for all participants was analyzed to understand what a "typical" charging curve looks like for given participants and vehicles. This was used to identify the coincidence factor associated with controlling a Level 2 residential EV charger.

All participants were controlled and monitored via a two-way communication capable DR control device. The device was capable of controlling load and recording data in 5- or 15-minute intervals. This daily interval data was collected and analyzed to determine charging demand (kW) curves, coincidence with System peak, and the duration of charging periods.

In order to understand the logistics and effects of DR on EV charging (and vice-versa), up to twelve 4- to 6-hour DR events were dispatched during two summer seasons.

Customers who participated in the pilot as well as other EV owners were surveyed about their EV use and their likelihood to participate in future EV charging related pilots. The results of those surveys are discussed in the section "Participant Feedback" section of this report.

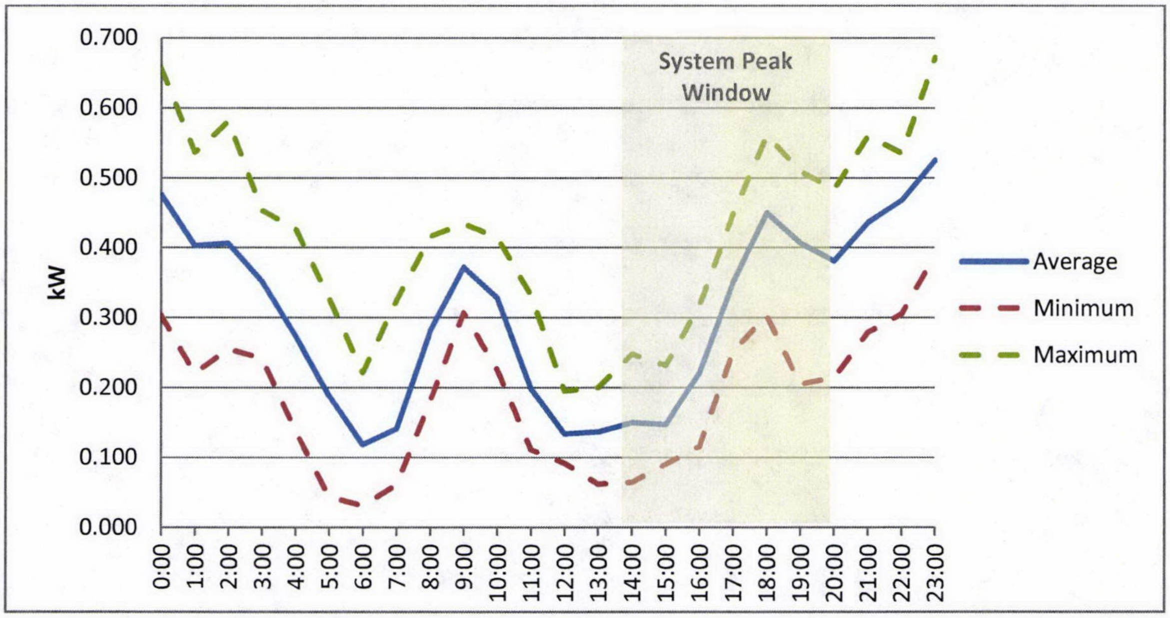
Charging Demand (kW) Curves

There are many ways the data can be presented in regards to the demand curves. The shape of the curve displayed by total average, vehicle type, month-to-month, weekday vs. weekend, etc. shows a similar trend with charging hitting peak levels generally from 10:00 p.m. to 1:00 a.m., and then a secondary peak around 10:00 a.m. The shaded area of Figures 3-7 below illustrates the typical window of time of Xcel Energy's System peak demand (2:00 – 8:00 p.m.).

EV Charging Load Profiles – Average of All Pilot Participants

Figure 3 illustrates the average profile of the combined 20 participants in the pilot. The highest usage period is in the late night hours. Interestingly, there is a second peak usage period around 9:00 a.m. Analysis of individual usage patterns shows large diversity in charging habits month to month. Generally, most charging is done in the evening hours and approximately 20% of participants charge mid-morning. This smaller group that charges between 9:00 a.m. and noon accounts for the secondary peak we see in the average profile.

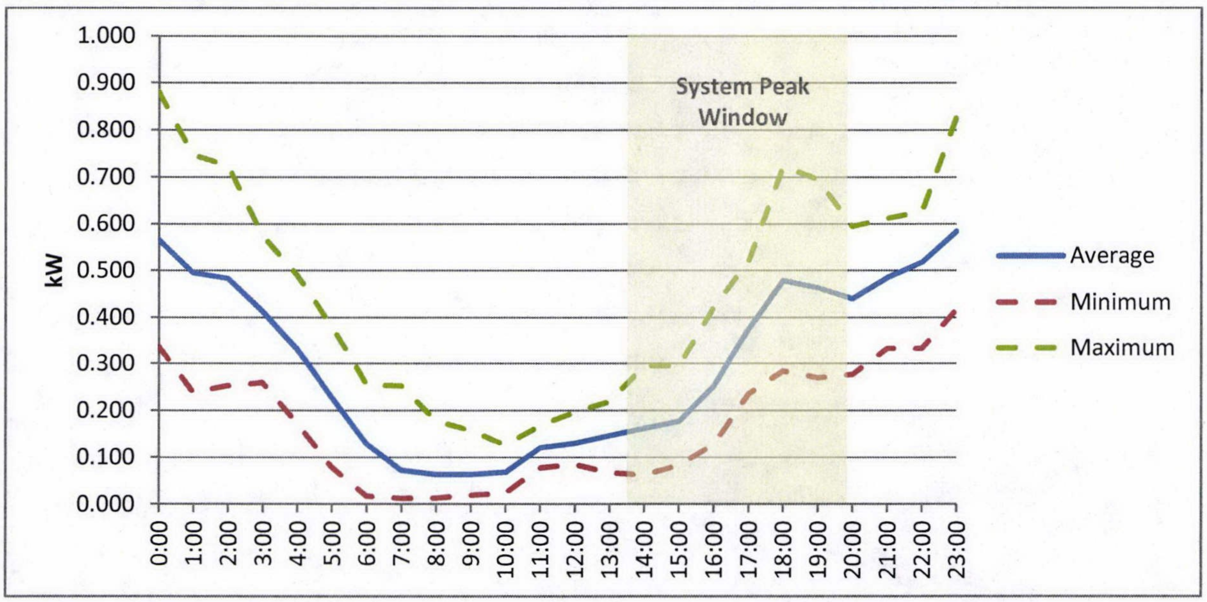
Figure 3: EVCS Pilot: Average Load Profile



EV Charging Profiles – Average of Pilot Participants without "Morning Chargers"

Since the load shape overall included a secondary peak, something that appeared to be a unique characteristic of this pilot, the data was further analyzed to determine who was doing major charging in the morning. These four participants were pulled out and the remaining participant's load shapes were included in Figure 4.

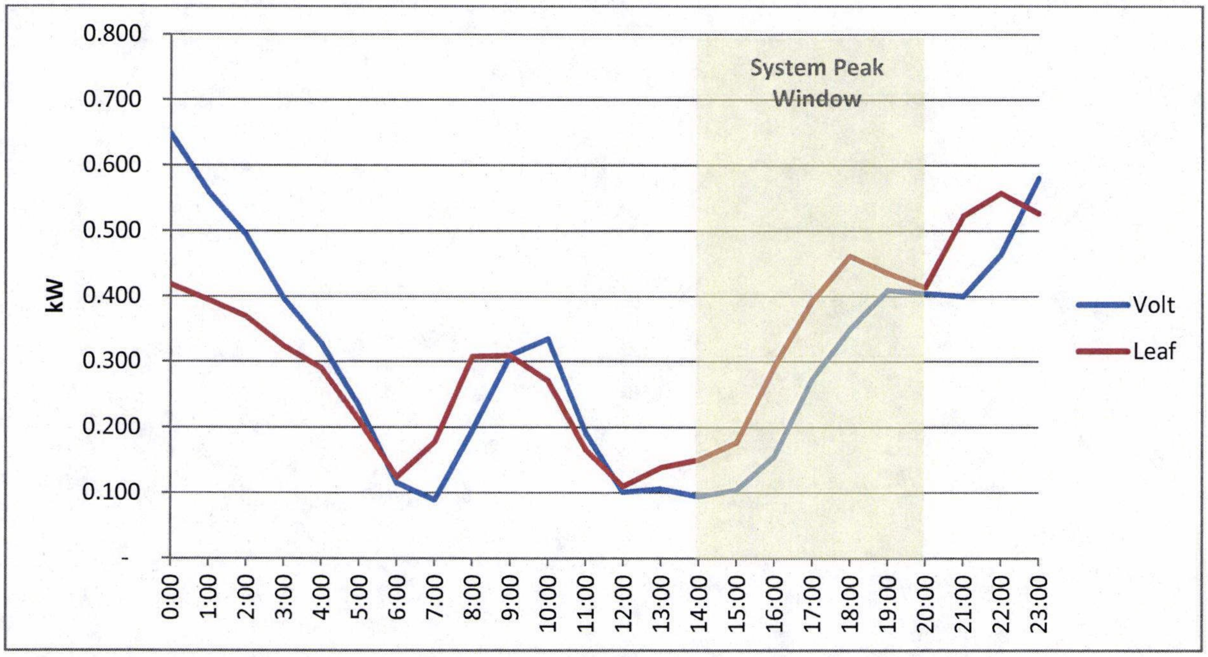
Figure 4: EVCS Pilot: Average Load Profile without "Morning Chargers"



EV Charging Profiles – Nissan Leaf vs. Chevy Volt Owners

Figure 5 illustrates charging profiles are similar between Nissan Leaf and Chevy Volt owners in the pilot. As you can see, the shapes are similar with the Volt owners charging a bit later in the day. This was not investigated further as charging profile differences between EV models was not of primary investigation for the pilot.

Figure 5: Load Profile: Leaf vs. Volt Owners



Seasonality with EV Charging

There appears to be some seasonality to the level of charging, with the lowest average load during the summer months regardless of the time of week (weekday or weekend). However, as Figure 6 illustrates, the load profile is similar across the seasons.

Figure 6: Seasonal Load Profile: Weekdays

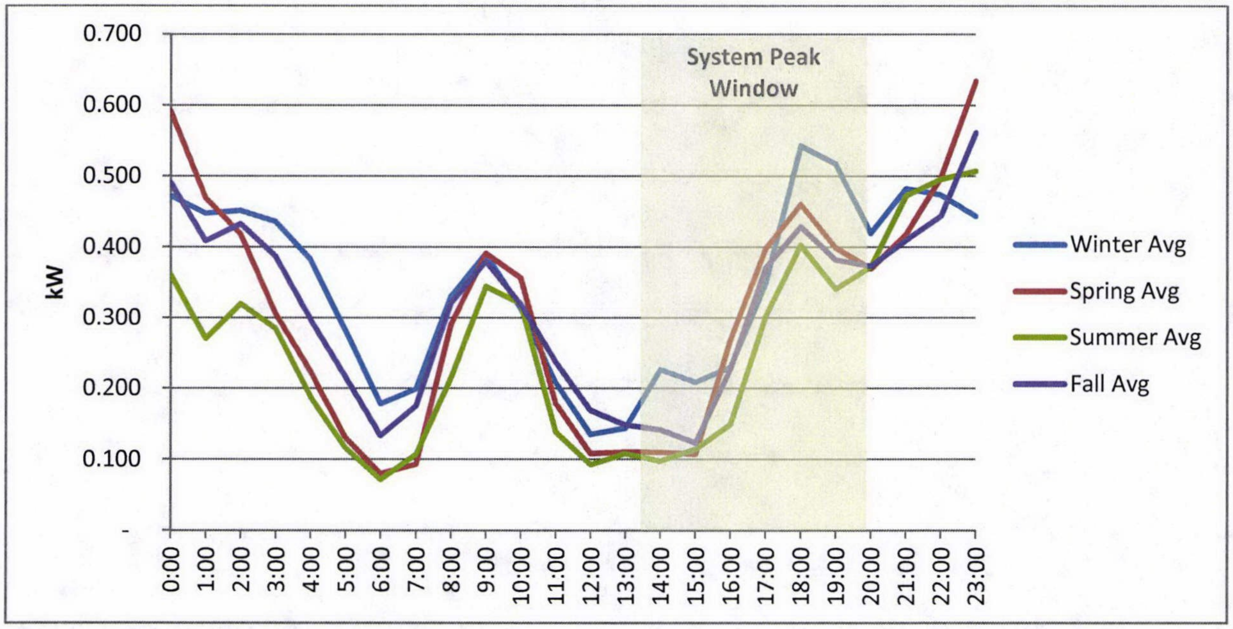
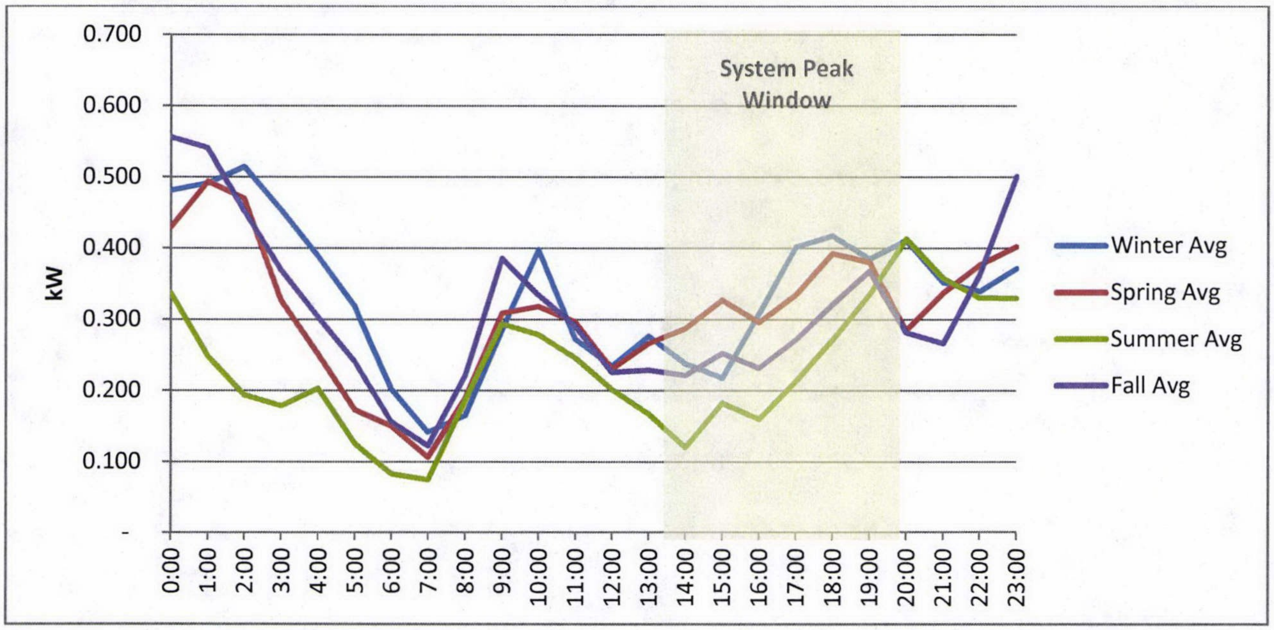


Figure 7: Seasonal Load Profile: Weekends



Coincidence with System Peak

The data from the EV pilot participants was multiplied across the "EV Class" which is defined here as the number of EV owners in Xcel Energy's Colorado service territory. The EV population at the time of this analysis was estimated to be 3,315. The peak month used for the derivation of load factor was July 2014.

Average Energy Use

The average monthly energy use of the pilot participants is shown in the table below and was extrapolated to the EV Class population to give an estimate of overall energy use of the total EV population in Colorado.

Figure 8: EVCS Average Monthly Energy Use

	Avg kWh/EV	Avg EV Class kWh
Oct 2013	244	809,329
Nov 2013	240	794,421
Dec 2013	244	808,014
Jan 2014	254	842,609
Feb 2014	240	795,170
Mar 2014	249	826,221
Apr 2014	220	730,100
May 2014	214	708,115
Jun 2014	176	584,583
Jul 2014	190	629,131
Aug 2014	187	619,481
Sep 2014	206	683,029
ANNUAL AVERAGE	**222**	**740,652**

Coincident Peak

The peak load of the EV Class does not appear to coincide with the Xcel Energy System peak as illustrated in Figure 10. However, even though absolute peak hour of EV charging doesn't coincide with the System peak hour, there is still a significant amount of charging occurring on peak.

It is important to note that the EV's in the pilot used Level 2 charging, which could have an electric demand requirement between 3.3 to 7.7 kW during a 3 to 8-hour charging period. The data for the pilot was analyzed on an hourly basis, so the 5 and 15-minute interval data was averaged for each hour of the day. This resulted in lower average hourly demands per vehicle as some 5 or 15-minute intervals within a 1-hour period had no charging and thus affected the average kW. See the table below for July7, 2014 between 9:00 p.m. and 11:00 p.m. For example, in Figure 9, Station 12 shows a 9:00 p.m. hourly average of 2.3 kW, when for 30 minutes it was at 3.9 kW.

Figure 9: Example of 15-minute Interval Data

Station #	1	2	3	4	5	11	12	13	14	15
9:00 PM	0.0	3.7	0.0	3.2	0.0	0.0	0.0	0.0	0.0	3.7
9:15 PM	0.0	3.7	0.0	3.4	0.0	0.0	1.3	0.0	0.0	3.7
9:30 PM	0.0	3.7	0.0	3.4	0.0	0.0	3.9	0.0	0.0	3.7
9:45 PM	0.0	3.7	0.0	3.4	0.0	0.0	3.9	0.0	0.0	3.7
AVG	**0.0**	**3.7**	**0.0**	**3.4**	**0.0**	**0.0**	**2.3**	**0.0**	**0.0**	**3.7**
10:00 PM	0.0	3.7	0.0	1.1	0.0	0.0	3.9	0.0	0.0	3.7
10:15 PM	0.0	3.7	0.0	0.0	0.0	0.0	3.9	0.0	0.0	3.7
10:30 PM	0.0	3.3	0.0	0.0	0.0	0.0	3.9	0.0	0.0	3.3
10:45 PM	0.0	0.6	0.0	0.0	0.0	0.0	3.9	0.0	0.0	1.1
AVG	**0.0**	**2.8**	**0.0**	**0.3**	**0.0**	**0.0**	**3.9**	**0.0**	**0.0**	**2.9**

Analysis of the 15-minute interval data on the Xcel Energy CO System peak day of July 7, 2014, revealed that only 5% of the pilot participants (1 out of 20) were charging at the System peak hour of 5pm.

A review of the hourly data revealed that at most only 50% of vehicles in the pilot were charging at the same time during any particular hour.

The peak charging hour for the pilot participants doesn't align with the System peak as illustrated in the following table. And at the System peak hour, 0.55 kW of load per vehicle is projected at most.

Figure 10: Hourly Peak Times and Average Loads

	EV Class peak time	*EV Class peak (kW)*	*Per Vehicle (kW)*	*SYSTEM peak time*	*EV Class (kW)*	*Per Vehicle (kW)*
Oct 2013	10/01/13 11:00 PM	4,427	1.34	10/15/13 08:00 PM	195	0.06
Nov 2013	11/09/13 04:00 AM	4,355	1.31	11/21/13 06:00 PM	610	0.18
Dec 2013	12/12/13 02:00 AM	4,362	1.32	12/05/13 06:00 PM	1,807	0.55
Jan 2014	01/17/14 07:00 PM	3,853	1.16	01/05/14 07:00 PM	274	0.08
Feb 2014	02/11/14 08:00 AM	4,365	1.32	02/05/14 07:00 PM	1,391	0.42
Mar 2014	03/05/14 06:00 PM	4,234	1.28	03/01/14 07:00 PM	1,825	0.55
Apr 2014	04/17/14 12:00 AM	4,753	1.43	04/13/14 09:00 PM	414	0.12
May 2014	05/01/14 11:00 PM	5,207	1.57	05/28/14 06:00 PM	912	0.28
Jun 2014	06/29/14 08:00 PM	4,101	1.24	06/30/14 05:00 PM	1,050	0.32
Jul 2014	07/17/14 08:00 PM	4,347	1.31	07/07/14 05:00 PM	783	0.24
Aug 2014	08/16/14 12:00 AM	4,139	1.25	08/13/14 05:00 PM	891	0.27
Sep 2014	09/06/14 11:00 AM	4,047	1.22	09/03/14 05:00 PM	827	0.25
AVERAGE		**4,349**	**1.31**		**915**	**0.28**

Potential Future Impact

In looking at what point EV load becomes impactful on the Xcel Energy electric grid, below is a graph that estimates the growth of EV's across Colorado.

Figure 11: Projected EV Growth in Colorado

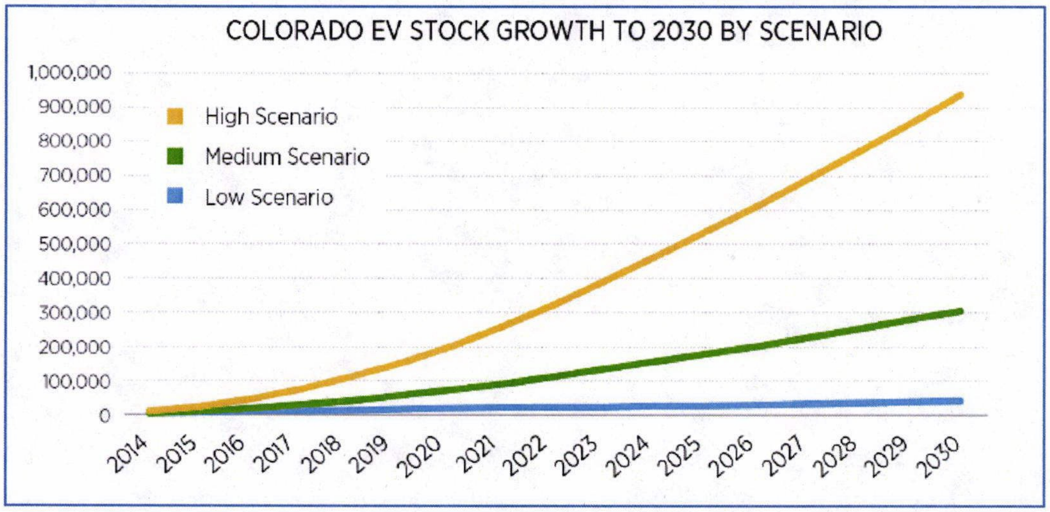


Image Source: BCS Incorporated, "*Colorado Electric Vehicle Market Implementation Study",* January 2015
Link to study

At an average monthly peak load of 1.31 kW per vehicle (average of "per vehicle" values in Table 2), by 2020 (using the High Scenario) the total average monthly peak load could be around 268 MW (1.6% of Xcel Energy's total Colorado generation capacity).

Contribution to the Coincident Peak Hour

The contribution to the monthly system peak was calculated for October 2013 through September 2014 for the EV Class (estimated 3,315 EV's in Xcel Energy's Colorado service territory).

Figure 12: EV Monthly Contribution to System Peak

	EV Class kW (3,315 EVs)	*Avg kW per Vehicle*
Oct 2013	195	0.06
Nov 2013	610	0.18
Dec 2013	1,807	0.55
Jan 2014	274	0.08
Feb 2014	1,391	0.42
Mar 2014	1,825	0.55
Apr 2014	414	0.12
May 2014	912	0.28
Jun 2014	1,050	0.32
Jul 2014	783	0.24
Aug 2014	891	0.27
Sep 2014	827	0.25

EV Charging Station Load Factors

There are several definitions of Load Factor. For purposes of this report we are focusing on two: 1) System Peak Load Factor and 2) Non-Coincident Peak (NCP) Load Factor.

System Peak Load Factor

The System Peak Load Factor is the ratio of the EV Class average demand in the system peak month to the EV Class peak demand at the system peak hour. For July 2014, this is:

$$\frac{\text{Average Demand}}{\text{Peak Demand}} = \frac{(629{,}131/744)}{783} = 1.08\ (108\%)$$

This says the average demand in July is 8% higher than at system peak hour. This is significant because it means that this load could be served by base load generation and it improves the System load factor as well.

Non-Coincident Peak Load Factor

The Non-Coincident Peak (NCP) Load Factor is the ratio of the EV Class average demand to the EV Class NCP demand. For July 2014, this is:

$$\frac{\text{Average Demand}}{\text{NCP Demand}} = \frac{(629{,}131/744)}{4{,}347} = 0.195\ (19.5\%)$$

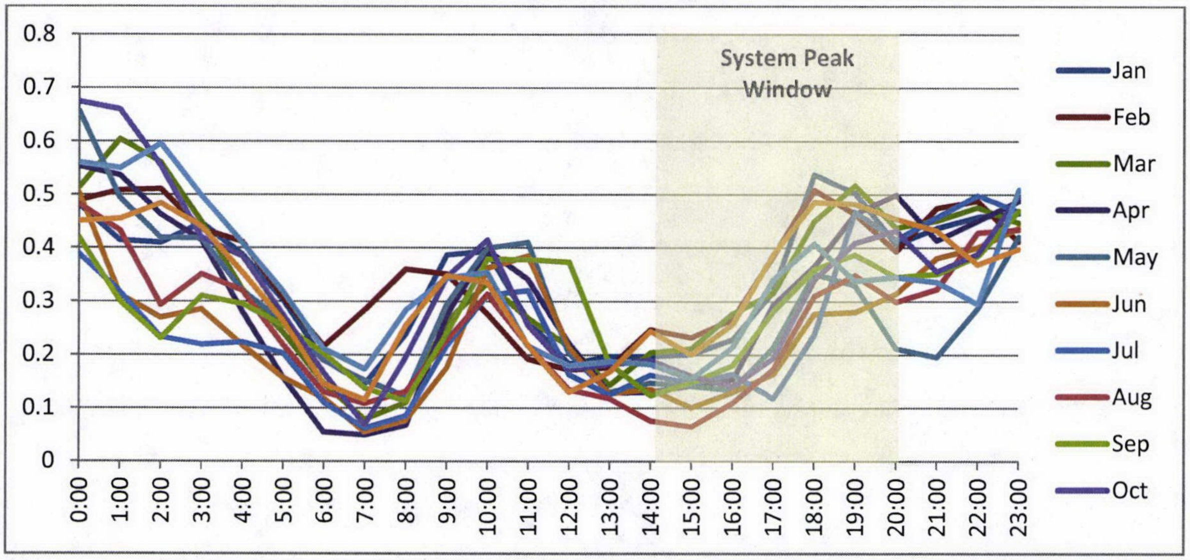
This says that if there was dedicated generation for EV charging, that generator would only be in use 19.5% of the time during July 2014.

Average Charging Profile

In order to profile the average EV charging day, the average kW across the twenty participants for each hour of each day of each month was calculated e.g. the average kW of 20 vehicles at 1am for every day in the year. This is attempting to profile the "typical day" of EV charging each month of the year.

Figure 13 illustrates the average load each hour for the twenty EV pilot participants for each month.

Figure 13: Average EV Charging Profile for Each Month

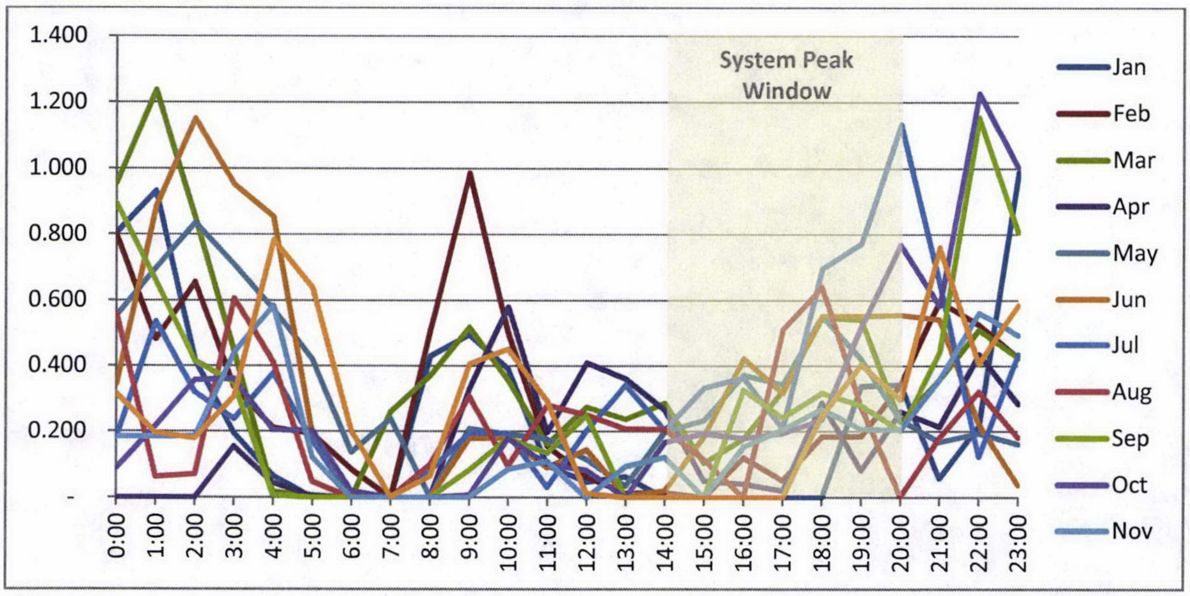


Peak Day Charging Profile

In order to profile the EV charging on System peak load days, the average kW across the twenty participants for each hour on the System peak day of each month was calculated e.g. the average kW of 20 vehicles at 1am for every day in the year. This is attempting to profile EV charging when the electric grid is at its peak load.

Figure 14 illustrates the average load each hour of the EV pilot participants on the peak day of each month. The monthly peak days between October 2013 and September 2014 are shown in Figure 10.

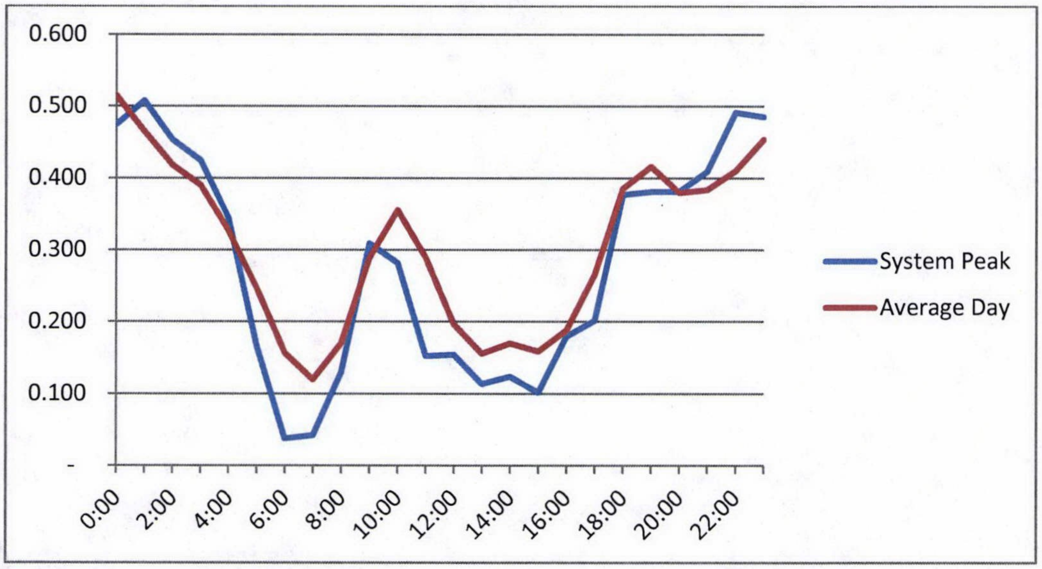
Figure 14: EV Charging Profile on Peak Day Each Month



Average Charging Profile vs. Peak Day Charging Profile

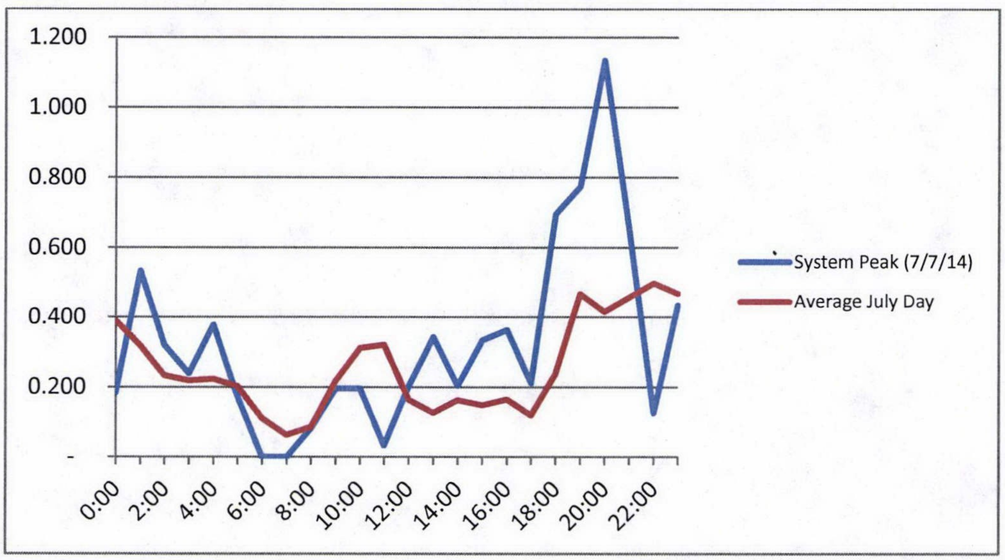
The following graph combines the two previous graphs in order to compare the Average EV charging profile over 12 months and the average EV charging profile on the System peak day for those same 12 months. This illustrates that on a system peak day, EV charging tended to be less than the average charging day in a month.

Figure 15: EVCS: Load on System Peak Day vs. Load on an Average Day



The following graph compares the profile of the average day in July with the Xcel Energy's Colorado System peak day.

Figure 16: EVCS: Average July Day vs. System Peak (7/7/14)



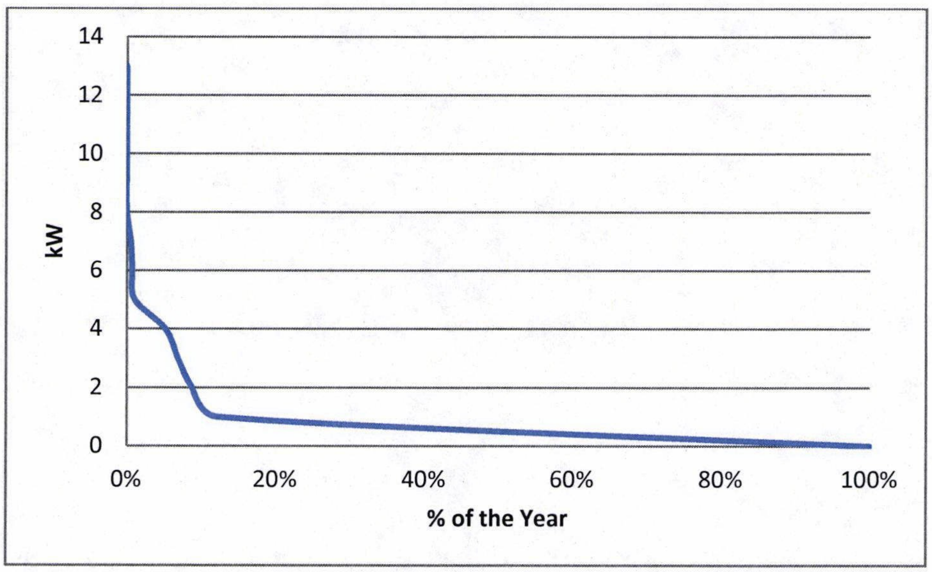
Charging Characteristics

The usage data provide some information on the various charging characteristics of the pilot participants such as when are customers charging and how long charging sessions last?

- Averaged charging trends show a pattern of charging throughout the day, where most (around 87%) charging takes place during off-peak hours
- There is an interesting bump in charging around 9am, which is attributable to about 20% of the pilot participants. Most participants do their charging at night.
- More kWh are used in the winter and fall, but the load profile is the same general shape as in spring and summer
- There is an appreciable amount of load available with each vehicle while charging (63% of load readings were between 2 and 4kW per vehicle).
- Charging sessions appear to run from 1 to 4 hours on average.

What is interesting about the charging data is how much of the time there is no charging taking place. In Figure 17, the graph shows the number of readings at different kW levels for all 20 stations in the pilot between 10/1/13 and 9/30/14. Around 86% of the readings were zero with the remaining majority of readings between 1 and 5 kW. The average hourly reading was above 5 kW less than 1% of the time.

Figure 17: Load Duration Curve



Cost-effectiveness

Looking at the simple benefit-to-cost, this pilot is not cost-effective from a Modified Total Resource Cost (MTRC) and Utility Cost Test (UCT) test ratio perspective. The MTRC test ratio is 0.09 and the UCT test ratio is 0.03 (a cost-effective product has a ratio of at least 1.0). Generally, pilots are not expected to be cost-effective, but the low TRC and UCT tests illustrate the low peak demand savings opportunity with EV Demand Response.

It may be more cost-effective to manage demand through workplace charging where it is more likely to be coincident with System peak load hours.

There are other factors to consider around cost-effectiveness. For instance, there is no broadly accepted lifetime for charging equipment. The life of the equipment may end due to failure or technology obsolescence. Additionally, unlike a home, with mostly fixed assets, the EV may only be at the house for a certain time before the customer moves. Similarly, if the vehicle is leased the potential life of the equipment for that customer may be the term of the lease.

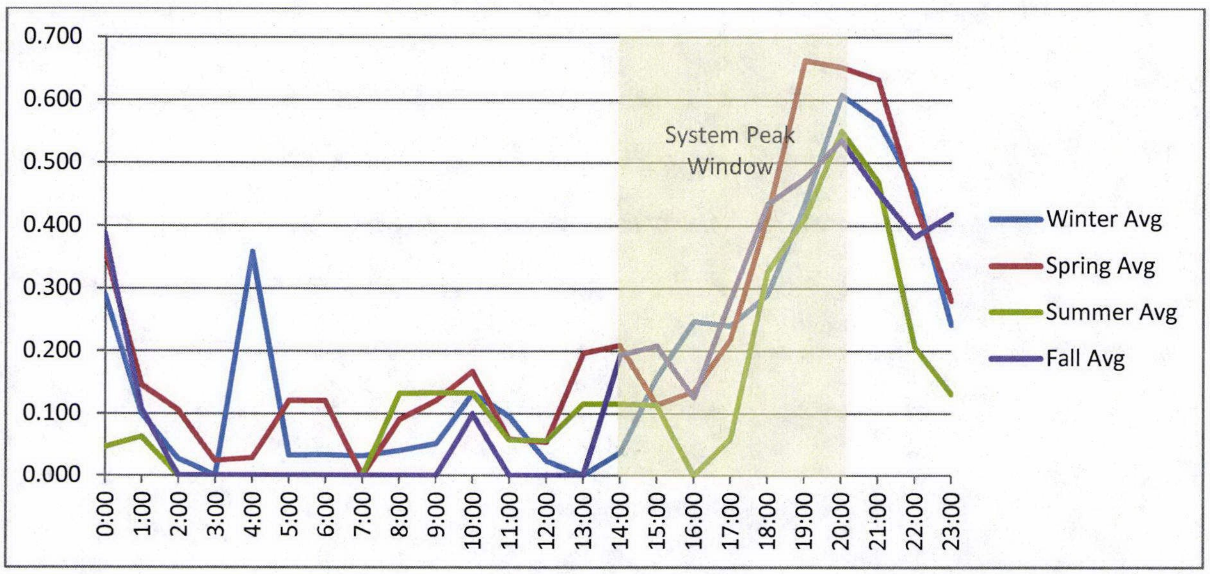
Electric Distribution System Impacts

EV Charging Profiles – Individual Stations

The Electric Distribution System is likely to be most impacted by EVs at the transformer level. Figure 18 below is an example of the load profile of one of the charging stations in the pilot, where the participant charges mainly in the evening hours and generally not in the morning. This profile is similar to other utility studies such as the "California Joint IOU Electric Vehicle Load Research Report" and "The EV Project".

The unique behaviors of individuals will likely play a role in determining how much of a concern the overloading of distribution transformers or low-voltage conditions on the distribution system really is. Many things have to align such as how many neighbors on the same transformer have EVs, the cycling of the EV charging itself, and the length of each charging cycle, coincidence of other loads, presence of rooftop solar, etc. Based on the data from the pilot, it would likely be a rare occurrence for vehicles to be charging at their maximum levels all at the same time as well as to start charging at exactly the same time.

Figure 18: Individual Station Example



Distribution System Capacity Impacts

In Q4 of 2014, Xcel Energy's Distribution Engineering Department presented a study of distribution capacity impacts of plug-in electric vehicles at the annual Minnesota Power Systems Conference (aka: MIPSYCON). The study looked at capacity concerns at the substation, feeder, and service transformer levels. The study concluded that Xcel Energy is 10+ years away from seeing any significant impact to mainline distribution feeders or substation transformers resulting from EVs.

Other key conclusions relating to the distribution system capacity impact of EVs:

- A 5% EV penetration rate (EVs per total number of residential customers) equates to 2-4% additional substation transformer peak load (worst case).
- Distribution feeder capacity significance starts around a 4% EV penetration rate and equates to a 2-4% demand growth per feeder.
- At a 5% EV penetration rate across the residential customer segment, potentially 4% of the distribution transformer population serving residential customers could be overloaded if charging is aligned with peak load times.
- Distribution transformer loading will be of most concern when there are multiple EVs served off the same transformer.

Participant Feedback

In December 2014, two surveys were completed to gather feedback from the pilot participants and general EV owners in Colorado. For the EV owners' survey, the Company reached out to an internal list of customers who had expressed interest in the Xcel Energy *Re-powering Transportation* initiative. The surveys were sent electronically through Survey Monkey. It was completely voluntary and there was no cash/gift incentive offered. Due to the power of social media, the Company received 61% of the responses from EV owners in Minnesota as information about the survey was passed on through Facebook. This data was not included in the analysis. Also, we found that there are many members on our email list that do not currently own EVs, but consider themselves "EV enthusiasts."

Pilot Participant Satisfaction Survey Summary

Eleven of the 20 pilot participants responded to the survey; Figure 21 shows overall satisfaction. Other key results include:

- 54.5% owned and 45.5% lease their EV.
- 45.5% are expecting to keep their EV from 1-3 years, 36.4% for longer than 3 years, and 18.2% for less than one year.
- 81.8% do not have access to EV charging at work.
- 82% of the participants were either somewhat or very satisfied with the pilot.

In regards to the logistics of the pilot itself, the survey participants were overwhelmingly supportive of the pilot operations; with data showing:

- A vast majority (91%) responded that 12 control events were a reasonable amount.
- 63.6% were mildly inconvenienced and 36.4% were not at all inconvenienced by the control events.
- 91% stated that they received the right amount of information of communication about the control events.
- 72.7% received the right amount of general information about the pilot. The rest felt that there was too little communication.

- 63.6% believed the $100/year incentive was an appropriate amount and 36.4% thought it wasn't enough.

Survey participants were also asked open-ended questions such as what went well with the pilot, what other comments they would like to make, etc. Some comments came back in support of a special rate for EV charging. Here are those comments:

"If Xcel Energy is serious about reducing electrical load during peak hours, it should ask the Colorado PUC to approve lower, off-peak electrical usage rates for residential customers. I would happily recharge my vehicle at home at night if the rates were lower at that time. Right now, Xcel Energy offers me no financial incentive to do that."

"If Xcel Energy were to provide lower, off-peak electrical usage rates for residential customers in Colorado, this would make sense."

"Any pilot programs that XCEL Energy could develop such as EV time of use charging and incentives toward Renewable charging of EVSE stations would be very complimentary..."

"Time of use rates are needed to encourage EV off peak charging and maximize efficient use of the electric grid."

"Off peak charging rate please!"

Most pilot participants surveyed do their EV charging almost exclusively at home (8 out of 11). The other three split their time between home and work or between home and businesses they frequent. The percentage of time at public charging stations (or elsewhere) is very low. Figure 20 below shows the overall average of those surveyed.

Figure 19: Percent of Time at Various Charging Locations

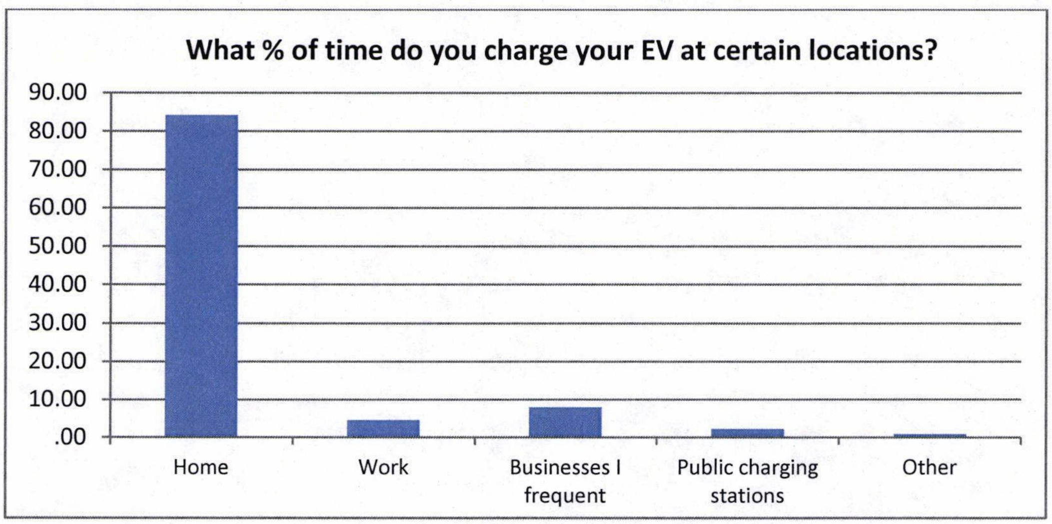
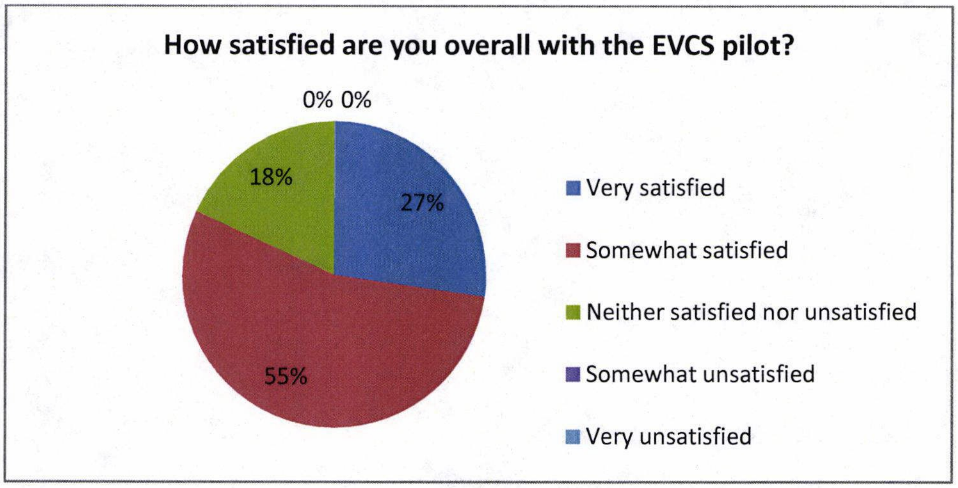


Figure 20: Overall Pilot Satisfaction

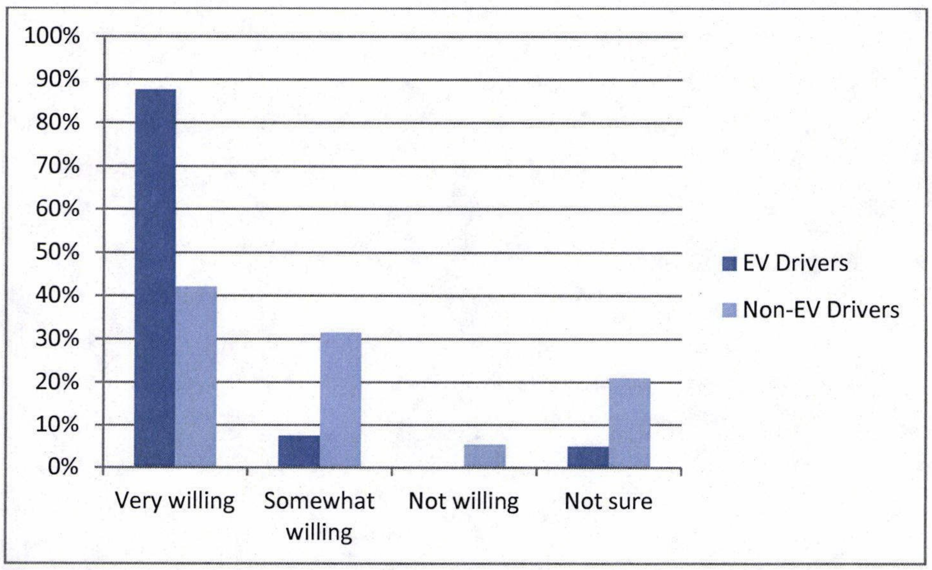


General EV Owner's Survey Summary

One of the main objectives of the survey to general EV owners was to gauge interest in participating in future utility pilots (either EV-related or not).

For future EV-related pilots, most EV drivers surveyed were very willing to participate, and most non-EV drivers were either very or somewhat willing to participate. See Figure 22 below.

Figure 21: Willingness to Participate in Future EV Pilots



Respondents (82 out of 100) wrote in reasons why they would be willing to participate, as shown in Figure 23.

Figure 22: Reasons to Participate in EV Pilots

Reason	#
Advancing Vehicle Adoption Interest	27
General interest	14
Societal interest (Altruistic)	14
Professional Interest	12
Environmental Interest	10
Innovation/Technological Interest	10
Self Interest (Mostly Financial)	3
More Charging Infrastructure Interest	2

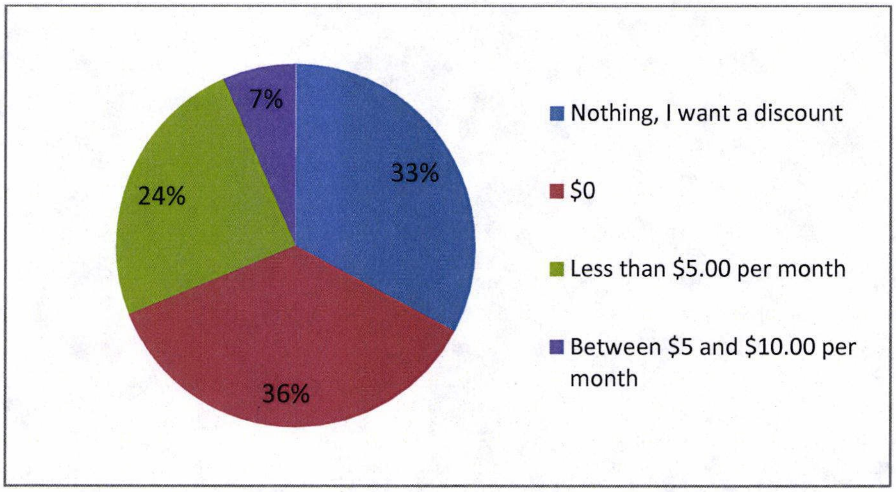
For future non-EV-related pilots, 92% of survey respondents they are either very or somewhat willing to participate in other pilots or programs to help Xcel Energy better understand customer behavior relative to electricity or natural gas consumption in general. Table 9 gives some reasons why.

Figure 23: Reasons to Participate in Other Utility Pilots

Reason	#
General interest	16
Advancing Utility Innovation Interest	11
Environmental Interest	10
Self Interest (Mostly Financial)	8
Societal interest (Altruistic)	7
Interested in EV's Only	7
Conservation of Energy	6
Innovation/Technological Interest	5

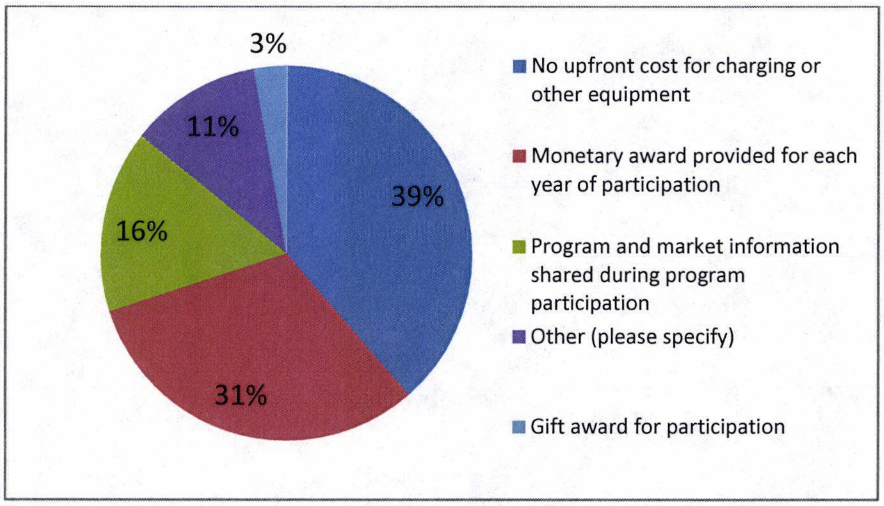
Survey participants were asked about program costs and benefits such as if they were open to pay more for an EV program that provides charging equipment that can communicate with the utility and how much they were willing to pay. Respondents were not willing to pay more than $10 per month.

Figure 24: Willingness to Pay for EV Program



Survey participants were then asked what would provide the greatest motivation to participate in such a program.

Figure 25: Motivation Factors to Participate in EV Program



Notable comments received:

- "I am glad Xcel is finally getting on board. I have been asking since Nov of 2011."
- "I'm glad to see that Xcel has finally showed some interest in EV's. When I started getting involved earlier this year there seemed to be no interest at all from Xcel. Also, information on rates for charging at various times of the day would be helpful."
- "I think that Xcel should be doing whatever they can to promote the purchase of electric vehicles and the cleanest generation sources for charging them at night."
- "I charge at home because I have solar panels on my home to offset the power consumption."
- "Typically charge overnight, or when rooftop solar is producing well."

Conclusion

The Electric Vehicle Charging Station pilot was a success in that it set out what it was intended to do:

- Understand customer charging patterns and behaviors,
- Understand how charging load coincides with Xcel Energy's system peak in Colorado,
- Show that it is technically and operationally feasible to interrupt vehicle charging through Demand Response (DR), and
- Predict how these vehicles may impact the distribution system

There is an appreciable amount of load available with each vehicle while charging (63% of readings are 2-4kW/vehicle, but vehicles are often not charging (88% of the hourly readings between 10/1/13 and 9/30/14 were zero) and generation dedicated for that load would only need to be available around 20% of the time. That reality means that there is not a lot of load available on average for DR events, and therefore not a lot of peak load savings.

EV charging does contribute to peak demand, but that contribution is not 100% coincident with System peak, and the variability in charging load can lead to high variable peak contributions from EVs (EV load at System peak hour, month by month).

It is important to note the level of sample size uncertainty inherent in the data. This could make it difficult to take away definitive conclusions about things like average charging load curves and demand response potential. At the same time, the demand response results were not cost-effective even if the most aggressive pilot results (maximum load of 20 participants) were used.

The cost of delivering the pilot as it was designed and the small amount of average peak load savings that were measured resulted in the pilot being not cost-effective. There is potential for cost-effective DR programs that leverage on-board charge control capabilities. However, because those program designs rely on customers paying for the cost of those onboard systems, the market size is unknown and could be small. Cost-effectiveness will face other challenges as we cannot count on a long useful life based on what we learned of EV ownership and what we don't know about the lifetime of the charging/control equipment.

Pilot participation and the survey results show that EV owners are a highly engaged group of customers. We might be able to design programs that take advantage of this fact, by motivating EV owners to shift load in different ways. But while feedback from the pilot was positive, these folks are the early adopters. Interest may be different for more mass-market EV drivers.

As it appears that a DR program may be difficult to be cost-effective, a next step for Xcel Energy may be to explore rate design options that can help manage load growth from EVs. Interest from the pilot participants as well as general EV owners and the cost of controlling charging directly also support exploring a rate that encourages off-peak charging. As rate design options are explored, potential for workplace charging access and load management will need to be considered.

Appendix A: EVCS Pilot Participant Satisfaction Survey

1. Do you own or lease your electric vehicle?
    - Own
    - Lease
2. How long are you likely to keep your electric vehicle?
    - 3 Years or more
    - 1 to 3 years
    - Less than 1 year
    - Other
3. How many miles do you travel in your electric vehicle per year?
    - <8,000
    - 8,000-10,000
    - 10,001-12,500
    - 12,501-15,000
    - >15,000
4. Roughly what percentage of time do you typically charge your electric vehicle at the following locations?
    - Home
    - Work
    - At businesses I frequent
    - Public charging stations
    - Other
5. Do you have access to electric vehicle charging at work?
    - Yes
    - No
    - Sometimes
6. Do you think up to 12 control events per summer is:
    - Too many
    - Too few
    - Just right
    - Don't know
7. How inconvenienced were you during the control events?
    - Very inconvenienced
    - Mildly inconvenienced
    - Not inconvenienced at all
    - Don't know / Don't recall
8. How was the level of communication about the control events?
    - Too much
    - Too little
    - Just right
9. How was the level of general communication about the pilot?
    - Too much
    - Too little
    - Just right
10. What is your opinion on the monetary incentive ($100/year) for your participation?
    - Too much
    - Too little
    - Just right
11. What is your overall satisfaction with the EVCS pilot?

- Very satisfied
- Satisfied
- Neutral
- Unsatisfied
- Very Unsatisfied

12. What do you thing went well with the pilot?
13. What could we do to improve the experience for future pilots?
14. How willing are you to participate in future electric vehicle-related pilots or programs designed to help Xcel Energy better understand the impacts electric vehicles have on customer electric consumption and the electric grid?
    - Very willing
    - Somewhat willing
    - Not willing
15. What would provide the greatest motivation to participate in such a program?
    - Monetary award provided for each year of participation
    - Gift awarded for participation
    - Program and market information shared during program participation
    - Other ____________________
16. How willing would you be to participate in other pilots or programs to help Xcel Energy better understand customer behavior relative to electric or gas consumption in general?
    - Very willing
    - Somewhat willing
    - Not willing
17. Is there anything else you would like to share with Xcel Energy staff related to your electric vehicle experience or the EVCS pilot?

Appendix B: EVSE Participant Willingness to Participate Survey

1. Do you own or lease your electric vehicle?
   - Own
   - Lease
2. How long are you likely to keep your electric vehicle?
   - 3 Years or more
   - 1 to 3 years
   - Less than 1 year
   - Other
3. How do you typically charge your electric vehicle at home?
   - Manufacturer-provided charging station (with a common 110V outlet)
   - Level 1 charging station
   - Level 2 charging station
   - Other
4. How often do you typically charge your electric vehicle?
   - More than once per day
   - Daily
   - A couple times per week
   - Weekly
   - Less than weekly
5. How many miles do you travel in your electric vehicle per year?
   - <8,000
   - 8,000-10,000
   - 10,001-12,500
   - 12,501-15,000
   - >15,000
6. At what time of day do you typically charge your electric vehicle?
   - Daytime hours
   - Overnight
7. Roughly what percentage of time do you typically charge your electric vehicle at the following locations?
   - Home
   - Work
   - At businesses I frequent
   - Public charging stations
   - Other
8. Do you have access to electric vehicle charging at work?
   - Yes
   - No
   - Sometimes
9. How willing are you to participate in electric vehicle-related pilots or programs designed to help Xcel Energy better understand the impacts electric vehicles have on customer electric consumption and the electric grid?
   - Very willing
   - Somewhat willing
   - Not willing
10. What would provide the greatest motivation to participate in such a program?
    - Monetary award provided for each year of participation
    - Gift awarded for participation
    - Program and market information shared during program participation

  - Other

11. How willing would you be to participate in other pilots or programs to help Xcel Energy better understand customer behavior relative to electric or gas consumption in general?
    - Very willing
    - Somewhat willing
    - Not willing
12. Is there anything else you would like to share with Xcel Energy staff related to your electric vehicle experience?

Appendix C: EV Growth Forecast

Vehicle Count	2020	2025	2030
High	203,692	537,239	937,216
Medium	72,598	177,978	302,429
Low	17,884	24,375	38,056

(Source: Colorado EV Market implementation Report)

Energy (kWh)	2020	2025	2030
High	542,576,685	1,431,049,602	2,496,472,861
Medium	193,380,114	474,082,012	805,583,548
Low	47,637,813	64,927,963	101,370,198

(Vehicle count times average kWh per year per vehicle of 2663.7 kWh)

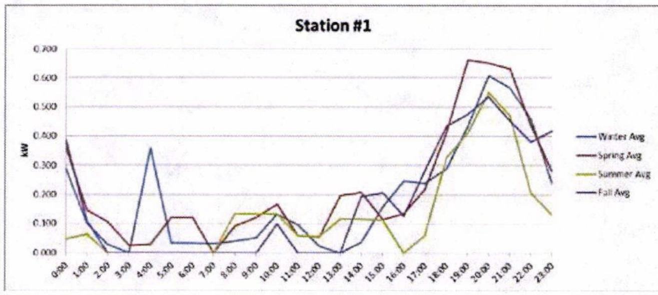
Total Demand (kW)	2020	2025	2030
High	267,346	705,126	1,230,096
Medium	95,285	233,596	396,938
Low	23,473	31,992	49,949

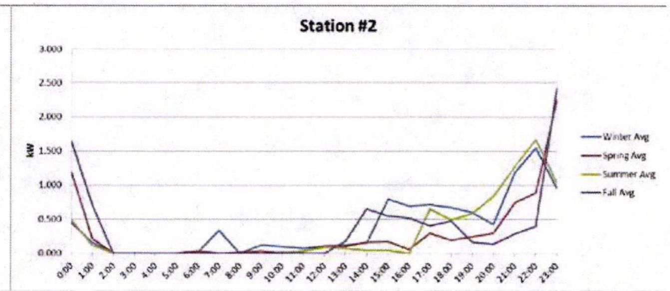
(Vehicle count times monthly kW average per vehicle of 1.31 kW)

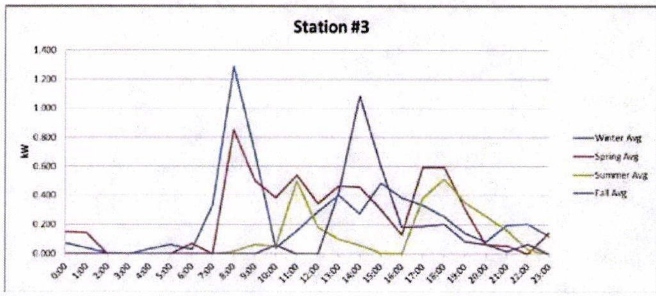
Coincidental Peak Demand (kW)	2020	2025	2030
High	150,112,883	395,923,723	690,690,825
Medium	53,501,831	131,162,690	222,878,115
Low	13,179,795	17,963,403	28,045,755

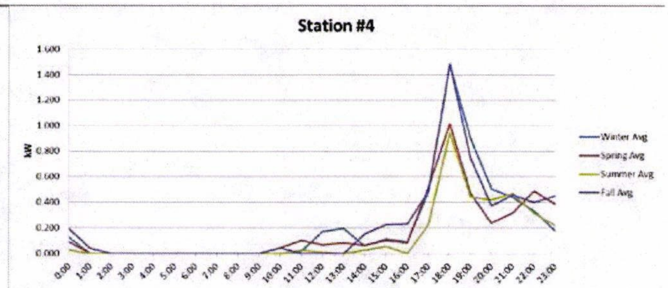
(Vehicle count times monthly kW average per vehicle of .28kW)

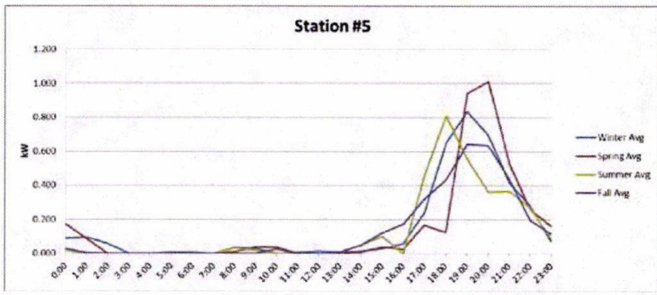
Appendix D: Individual Charging Station Average Daily Usage

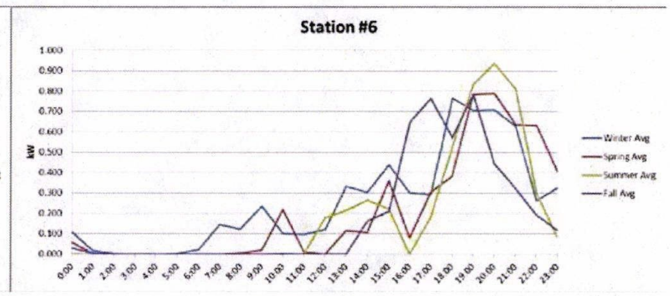


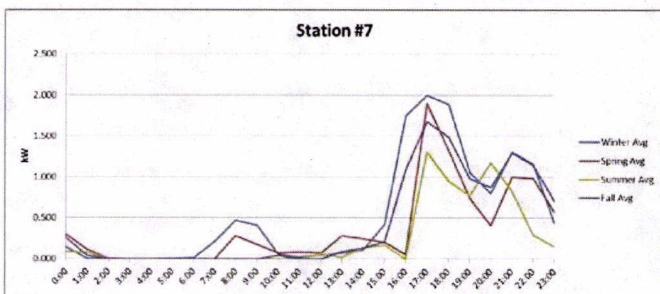


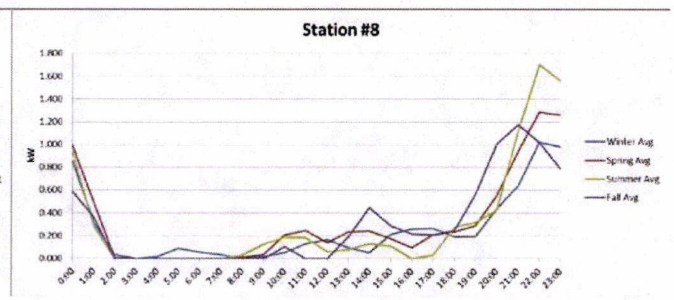


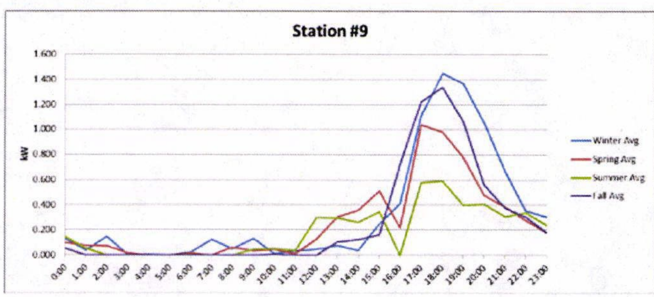


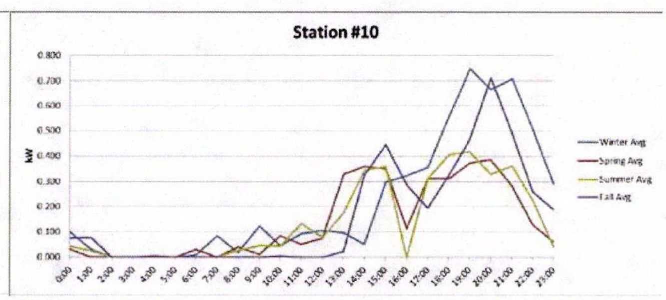


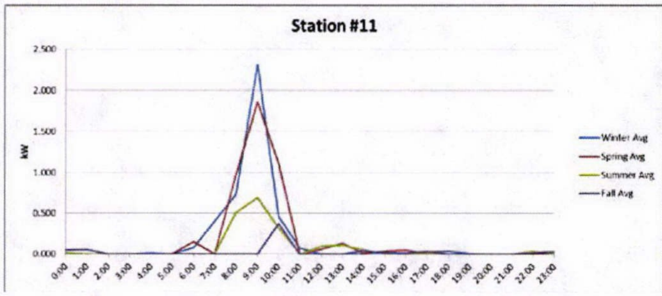








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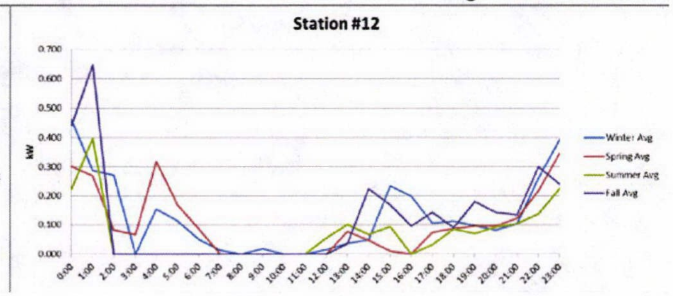
Spring Avg
Summer Avg
Fall Avg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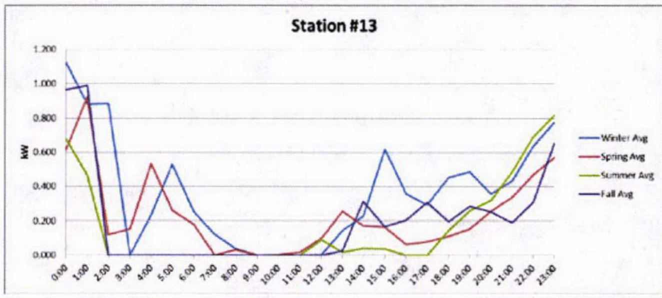
Spring Avg
Summer Avg
Fall Avg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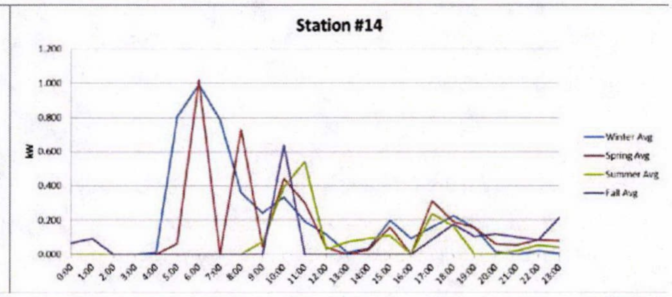
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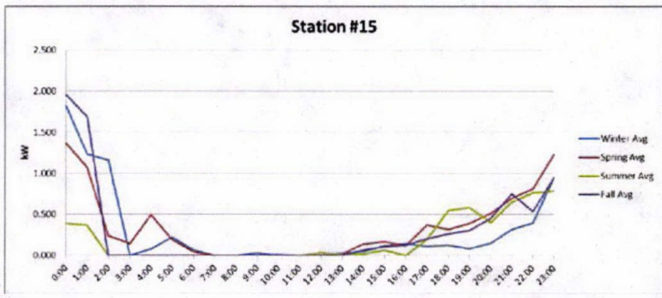
Spring Avg
Summer Avg
Fall Avg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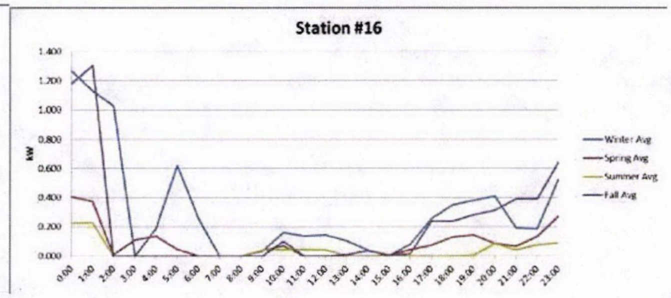
Spring Avg
Summer Avg
Fall Avg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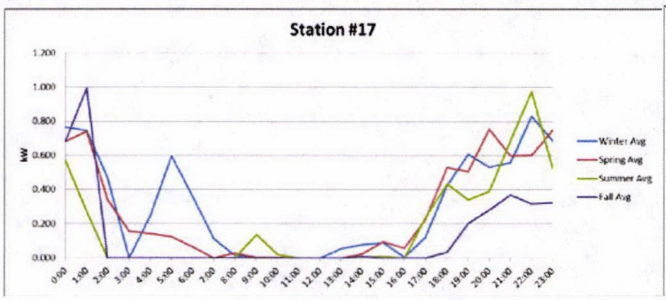
Spring Avg
Summer Avg
Fall Avg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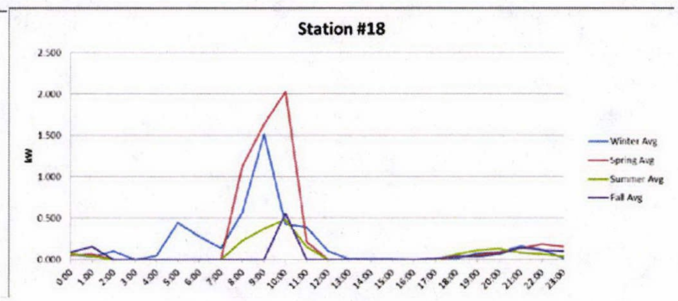
Spring Avg
Summer Avg
Fall Avg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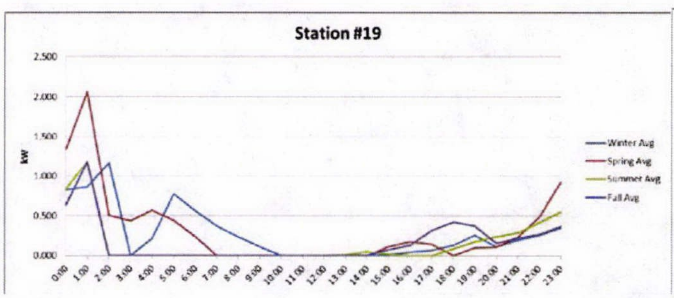
Summer Avg
Fall Avg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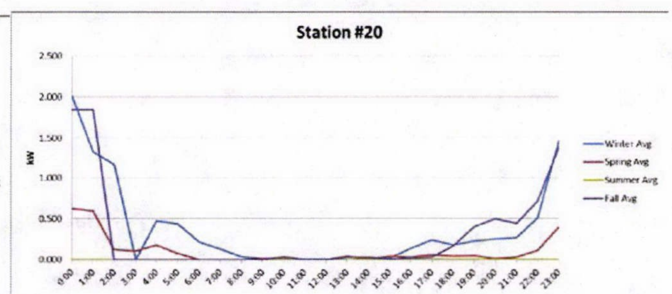

Station #20
kW
Winter Avg
Spring Avg
Summer Avg
Fall Avg

part 7

19950003

Frost

Witness Direct Testimony Summary

Witness: Nathan J. Frost

Title: Director – New Technology and Energy Conservation

Summary:

Company Witness Nathan J. Frost details the Company's plan for full deployment of smart meters and the associated infrastructure (together "AMI") as part of its proposal to transform its electric distribution grid (the "GT Plan"). Mr. Frost also addresses the elements detailed in the Final Order issued in the 2018 GT Plan proceeding ("2018 Final Order"), and discusses the proposed deployment of AMI, the proposed opt-out policy, and the Company's plan for customer education consistent with the 2018 Final Order, as well as the Company's initiatives related to electric transportation.

In terms of AMI, Mr. Frost testifies that the Company is proposing to fully deploy smart meters AMI across its Virginia service territory. Through AMI, the Company can remotely read smart meters and send commands, inquiries, and upgrades to individual smart meters, minimizing the need for field visits. From a foundational perspective, the over-arching benefit of full AMI deployment cannot be overstated. As Mr. Frost testifies, nearly every investment within the Grid Transformation Plan relies directly on or is enabled by full AMI deployment. Benefits from full deployment of AMI include operational efficiencies and increased information and control of the electric grid for the Company; customer benefits in savings, convenience, information, and reduced energy consumption; and additional benefits in reduced greenhouse gases.

Mr. Frost also discusses the proposed opt-out policy. As Mr. Frost explains, while Dominion Energy Virginia fully supports AMI and the benefits it provides, the Company understands that some customers may prefer not to have a smart meter and plans to accommodate those customers where practical, if deemed necessary by the Commission. Under the Company's proposed opt-out policy, residential customers taking basic service on Rate Schedule 1 with accounts in good standing will be eligible to opt out of smart meter installation upon request. As Mr. Frost testifies, the Company proposes to impose a one-time initial fee of $84.53 and an ongoing monthly fee of $29.20. These fees are intended to be revenue neutral.

In terms of electric transportation, Mr. Frost describes the proposed Smart Charging Infrastructure Pilot Program, under which the Company would offer rebates for incentives for infrastructure necessary for managed charging, also referred to as "smart" charging. In addition, the Pilot Program includes Company-owned charging at strategic locations. The information gained from the proposed Pilot Program will provide the Company with the data and tools necessary to understand and manage future EV charging load in furtherance of additional pilots, programs, or rate designs that will support EV adoption while minimizing the impact of EV charging on the distribution grid.

Mr. Frost additionally testifies as to the Company's education plan. The overarching goal for the plan is to educate customers, to raise awareness and understanding of the benefits of the GT Plan investments, and to encourage participation in future programs and offerings to fully maximize the benefits of the GT Plan. The plan specifically addresses education for full deployment of AMI and the Smart Charging Infrastructure Pilot Program, consistent with the 2018 Final Order.

**DIRECT TESTIMONY
OF
NATHAN J. FROST
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUR-2019-00154**

Q. **Please state your name, business address, and position of employment.**

A. My name is Nathan J. Frost and my business address is 600 East Canal Street, Richmond, Virginia 23219. I am Director of New Technology and Energy Conservation for Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company"). A statement of my background and qualifications is included as Appendix A.

Q. **Please describe your area of responsibility with the Company.**

A. I am responsible for delivering advanced metering and demand side management solutions for Dominion Energy Virginia. I am also responsible for integrating new technologies and developing renewable energy and energy conservation programs within the Company's regulated service territory.

Q. **What is the purpose of your testimony?**

A. The purpose of this testimony is to detail the Company's plan for full deployment of smart meters and the associated infrastructure (together "AMI") as part of its proposal to transform its electric distribution grid (the "Grid Transformation Plan," "GT Plan," or "Plan"). I will specifically address the elements detailed by the State Corporation Commission of Virginia (the "Commission") in its Final Order dated January 17, 2019, in Case No. PUR-2018-00100 (the "2018 Final Order"), and I will discuss the proposed deployment of AMI, including detailed cost estimates for the investments proposed during 2019, 2020, and 2021 ("Phase IB"); the proposed opt-out policy; and the Company's plan for customer education consistent with the 2018 Final Order.

I will also discuss the Company's initiatives related to electric transportation, including the Smart Charging Infrastructure Pilot Program that the Company proposes as part of the GT Plan, as well as customer education proposals.

Q. **During the course of your testimony, will you introduce an exhibit?**

A. Yes. Company Exhibit No. __, NJF, consisting of Schedules 1 through 10, was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief. The table below provides a description of these schedules:

Schedule	Description
1	Cost Schedule
2	Sample Smart Meter Post Card
3	Sample Smart Meter Door Hanger
4	Current Opt-Out Customer Information Package
5	Proposed Opt-Out Policy
6	Opt-Out Fee Breakdown
7	Proposed Update to Terms and Conditions
8	Opt-Out Fee Comparison
9	Navigant Forecast for Electric Vehicles
10	Department of Energy EVI-Pro Lite Tool Results

Additionally, I sponsor Filing Schedule Frost, Attachments A through C, which provide summaries of executed contracts and request for proposals ("RFP") from which detailed pricing estimates were prepared. The table below provides a description of these filing schedules:

Filing Schedule Frost	Description
Extraordinarily Sensitive Attachment A	RFP Summary for Meter Purchases
Extraordinarily Sensitive Attachment B	RFP Summary for Meter Exchange Vendors
Extraordinarily Sensitive Attachment C	RFP Summary for Workplace Charging

Other supporting documents include:

- AMI Master Service Agreement

This document is not included with my filing schedules due to its voluminous nature; however, the Company will make this document available electronically.

I also sponsor certain sections of the Grid Transformation Plan, the executive summary of Dominion Energy Virginia's plans for grid transformation (the "Plan Document"), as indicated in Appendix A to the Plan Document. Finally, I sponsor the metrics categories as identified in Company Witness Edward H. Baine's Schedule 2.

Q. **Did you provide information to West Monroe Partners, LLC ("West Monroe") for use in the cost-benefit analysis ("CBA")?**

A. Yes, I provided costs and additional inputs for AMI, electric transportation initiatives, and customer education to West Monroe for use in the CBA. I also support the benefits reflected in Company Witness Thomas G. Hulsebosch's Schedule 2, as identified therein.

The specific costs I support in Phase IB are:

Nominal $, in Millions	**2019**	**2020**	**2021**	
	Year 1	**Year 2**	**Year 3**	**3-year Total**
Phase IB	$17.2	$83.1	$120.4	$220.8
Capital	$14.9	$73.3	$102.7	$190.8
O&M	$2.4	$9.8	$17.8	$29.9

My Schedule 1 provides detailed cost information for the GT Plan components that I sponsor.

Q. Mr. Frost, how is your testimony organized?

A. My direct testimony is organized as follows:

I. Smart Meter Deployment
- A. Existing System, Need, and Proposed Deployment Plan
- B. Cost Estimates
- C. Benefits of AMI
- D. Alternatives Considered
- E. Customer Education
- F. Opt Out

II. Electric Vehicles
- A. Existing System, Need, and Proposed Deployment Plan
- B. Cost Estimates
- C. Benefits of Smart Charging Infrastructure Pilot Program
- D. Alternatives Considered
- E. Customer Education

III. Conclusion

I. SMART METER DEPLOYMENT

Q. Please provide a brief overview of the Company's plan to deploy AMI as part of the Grid Transformation Plan.

A. Dominion Energy Virginia proposes to fully deploy AMI across its service territory. Through this technology, the Company can remotely read data gathered by smart meters and send commands, inquiries, and upgrades to individual smart meters, minimizing the need for field visits. The full deployment of AMI is a foundational component of the Grid Transformation Plan, effectively enabling all other Plan components. Benefits from full deployment of AMI include operational efficiencies and increased information and control of the electric grid for the Company; customer benefits in savings, convenience, information, in reduced energy consumption; and additional benefits in reduced greenhouse gases.

Q. Does the full deployment of AMI meet the definition of an electric distribution grid transformation project under Va. Code § 56-576?

A. Yes, the definition of "electric distribution grid transformation project" in Va. Code § 56-576 specifically includes "advanced metering infrastructure."

Q. You mentioned that you will address elements related to AMI required by the 2018 Final Order. What are those elements?

A. In the 2018 Final Order, the Commission denied the Company's proposal to fully deploy AMI, but did so without prejudice to the Company seeking approval of the deployment in future petitions in compliance with requirements set forth in the 2018 Final Order. The Commission specified the elements related to AMI deployment that the Company should include if it chooses to pursue the deployment on pages 10-11 of the 2018 Final Order:

> If Dominion [Energy Virginia] chooses to proceed with a proposal for full deployment of AMI, its next proposal should be supported by a detailed and comprehensive plan for evaluation that addresses, at a minimum, the following elements:
>
> a. Detailed cost estimates for all AMI-related spending.
>
> b. Any plan for time-varying rates; and whether any such offering would be the default tariff for a customer with an installed smart meter.
>
> c. Any customer "opt-out" provision, both as to smart meter installation and time-varying rates, under all tariff scenarios for those consumers who so choose and to protect particularly vulnerable customers, such as those with medical conditions that reduce their ability to manage energy usage; and any fees proposed by the Company to be charged to customers who choose to opt-out both as to time-varying rates and smart meter installation.

d. Analysis of how any plan promotes demand response, energy efficiency, and conservation.

e. A transition plan including adequate customer education.

The full deployment of AMI is foundational to the Grid Transformation Plan and many other Company initiatives. My testimony will address each of these elements, as well as other relevant information to prove that the full deployment of AMI is reasonable and prudent.

Q. On page 12 of the June 27, 2019 Final Order in Case No. PUR-2018-00065 ("2018 IRP Final Order"), the Commission ordered the Company in future integrated resources plans ("IRPs") to "systematically evaluate long-term electric distribution grid planning and proposed electric distribution grid transformation projects. For identified grid transformation projects, the Company shall include: (a) a detailed description of the existing distribution system and the identified need for each proposed grid transformation project; (b) detailed cost estimates of each proposed investment; (c) the benefits associated with each proposed investment; and (d) alternatives considered for each proposed investment." (Internal footnotes omitted.) Although this is not an IRP proceeding, does your testimony address these requirements as they relate to AMI?

A. Yes, I will discuss each of these items. I will also discuss the proposed deployment plan for AMI, the proposed opt-out policy, and the Company's plan for customer education consistent with the 2018 Final Order.

A. <u>Existing System, Need, and Proposed Deployment Plan</u>

Q. What is the current make-up of the meter population across Dominion Energy Virginia's service territory?

A. Dominion Energy Virginia serves approximately 2.54 million customer accounts in Virginia. As of July 1, 2019, approximately 78% of Virginia customer meters were automated meter reading ("AMR") meters, approximately 17% were smart meters, and approximately 5% were manually read meters. Section III.D of the Plan Document provides details on these meters and how they function.

Q. What is the need driving the full deployment of AMI?

A. The full deployment of AMI is needed to enable the functionality of a transformed grid and to meet the needs and changing expectations of our customers. The Company's existing AMR meters have served the Company and its customers well but have functional limitations. The existing AMR meters:

- Cannot provide interval energy usage data or demand readings, without which the Company cannot effectively provide detailed usage information to its customers nor offer more advanced rate options like time-varying rates;
- Cannot capture operational conditions in real time or on demand, such as outage information and meter tampering;
- Cannot provide real-time premises level voltage, which is critical to integrating distributed energy resources ("DERs") and enabling advanced analytics;
- Cannot be remotely controlled or operated, meaning that the Company must send a field representative for common requests.

Q. **What is AMI and how does it function?**

A. The term AMI, or "advanced metering infrastructure," refers to the over-arching metering system, which includes smart meters, a field area network, and a back office system called the AMI head-end system.

Smart meters are electric meters that digitally gather energy usage data in specified increments (*i.e.*, interval data) and other related information. Examples of the information captured by smart meters include energy usage, demand, voltage, and meter temperature, as well as other real-time information regarding the operational status, self-diagnostics, power quality, and condition of the electric grid at the customer premises—enabling the meter to function as an end-of-line sensor at the customer premises.

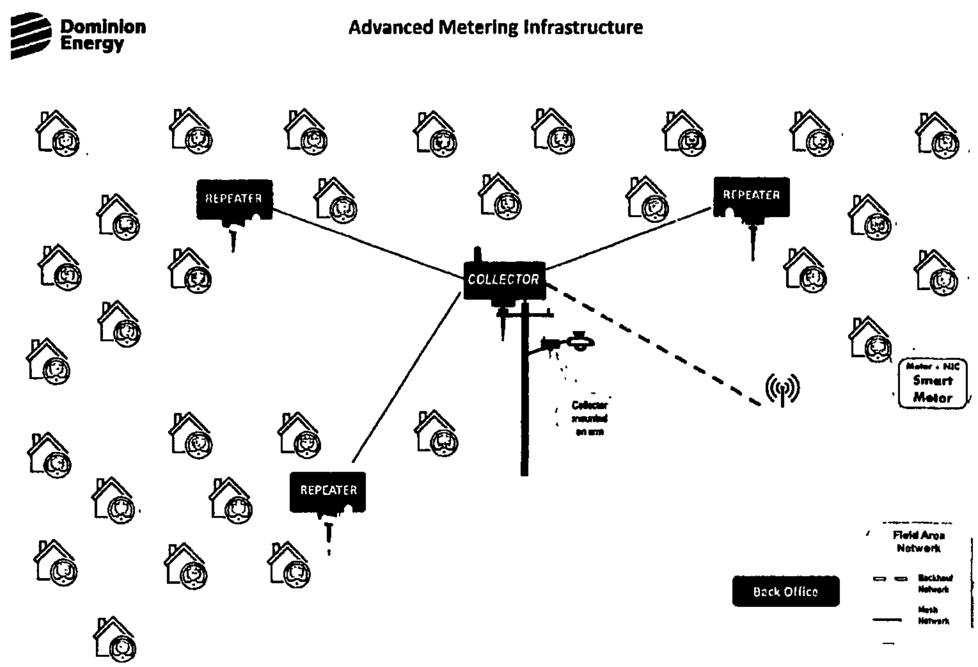
Smart meters are equipped with a network interface card ("NIC") and communicate with each other, creating what is referred to as a mesh network. The higher the density of smart meters, the stronger the mesh network.

A system of field telecommunications devices—comprised of devices called repeaters and collectors—gathers meter data from the mesh network and transmits the data gathered back to the utility through a backhaul network. Together, the mesh and backhaul networks are called the field area network.

A head-end system receives and processes the data and serves as an operating platform for the back office team responsible for operating and maintaining AMI. The head-end system also provides information from smart meters to other Company operating and analytical systems such as the meter data management system, the customer information system, and the outage management system, including valuable, real-time information regarding the operational status and condition of the electric grid at the customer premises.

Figure 1 provides a visual representation of the components of AMI and how they depend on each other to function.

Figure 1: Advanced Metering Infrastructure



Q. **Does the Company have experience with AMI?**

A. Yes. In 2008, the Company began to deploy AMI technology in a targeted fashion based on specific operational and customer needs. The Company did this at a measured pace over the course of several years during which time we refined our expectations of supplier and technology capabilities and developed operational experience through realworld application. Following a competitive bidding process, the Company continued to deploy smart meters in larger quantities and densities in diverse geographical areas of our service territory in order to validate deployment and operational strategies. The Company used the knowledge gained from this limited deployment of AMI to develop its strategy for full deployment across the service territory.

Q. **How does the Company propose to deploy AMI throughout the service territory?**

A. The Company expects to complete deployment of AMI over a six-year period beginning in 2019. During this time, the remaining approximately 2.1 million smart meters and 3,100 network devices will be deployed in a structured manner across the Virginia service territory office-by-office, with deployment occurring in multiple offices at the same time.

Within each office, the first step is to establish the field area network by deploying network devices (*i.e.*, repeaters and collectors). Next, the deployment of smart meters occurs, which fills in the mesh network, resulting in a robust, secure, and reliable network for two-way communication. As smart meters are deployed, their levels of communication and performance in the context of the growing AMI footprint are monitored and measured against established criteria. After the installation of smart meters in a given office is complete, a period of network optimization will take place where communication levels are measured, and additional network devices may be deployed to further bolster communications.

Table 1 details the projected plan for full deployment of AMI as measured by the number of smart meters installed in a given office.

Table 1: Smart Meter Deployment Plan

Region	Office	2019	2020	2021	2022	2023	2024	Total
Central	Richmond	40,000	124,000	2,000				166,000
Northwest	Orange	11,000						11,000
Eastern	Williamsburg		51,000					51,000
Eastern	Norfolk		58,000	43,000	1,000			102,000
Eastern	Peninsula		103,000	74,000	2,000			179,000
Central	Petersburg		40,000	62,000	3,000			105,000
Eastern	VA Beach			188,000	11,000	3,000		202,000
Central	East Richmond			80,000	19,000	2,000		101,000
Eastern	Chuckatuck			64,000	65,000	2,000		131,000
Northwest	Woodbridge			40,000	55,000			95,000
Northwest	Warrenton				33,000			33,000
Central	Midlothian				118,000	29,000	1,000	148,000
Northwest	Leesburg				81,000	1,000		82,000
Central	Fredericksburg				79,000	32,000		111,000
Eastern	Chesapeake				75,000	2,000		77,000
Northwest	Fairfax				15,000	107,000	1,000	123,000
Central	Southside					19,000		19,000
Northwest	Blue Ridge					61,000		61,000
Central	Farmville					25,000		25,000
Central	Altavista					14,000		14,000
Northwest	Rockbridge					15,000		15,000
Central	South Boston					20,000		20,000
Northwest	Springfield					40,000	97,000	137,000
Central	Northern Neck						24,000	24,000
Northwest	Alleghany						14,000	14,000
Central	Gloucester						44,000	44,000
Northwest	Shenandoah						20,000	20,000
	TOTALS	51,000	376,000	553,000	557,000	372,000	201,000	2,110,000

For simplicity, the totals represent rounded figures. A very small sub-set of meter replacements may require special equipment and handling that may cause actual completions to fall outside of the years indicated above.

Q. **What was the rationale used to determine this deployment plan?**

A. The major determining factors for the full deployment plan were metering operations efficiency, deployment efficiency, and geographic diversity. Looking first at operations, the Company analyzed which areas in its service territory require the highest number of truck rolls for basic meter-related service order types. Such requests can be performed remotely once AMI is deployed, and fewer truck rolls will lead to lower cost of service components and reduced greenhouse gas emissions. The Company prioritized field offices based on this analysis; offices that would experience the largest reduction of truck rolls, like Norfolk, Peninsula, and Petersburg, were pulled forward in the deployment plan.

The Company also considered deployment efficiencies in developing its plan. Deploying an entire office and then neighboring offices improves efficiencies for deployment resources and allows support resources to train in one area on the new technology before starting up a team in another area. Additionally, as mentioned previously, smart meters communicate with each other to form the mesh network. Without a strong mesh network, smart meters cannot communicate with the backhaul network. And without the mesh and backhaul network, no two-way communications between the Company and the customers' smart meter exist to enable meter reading and remote functionality or any of the other benefits associated with smart meters. For these reasons, the Company has and proposes to continue to deploy AMI office-by-office, which will ensure operational efficiency and cost effectiveness.

Finally, the Company also incorporated geographic considerations into the deployment plan, ensuring that each of its three regions has deployment activity by 2021, but giving early preference to Central and Eastern regions based on the focus of previous deployments in Northwest region and the truck roll reduction potential in these areas.

Q. Table 1 shows a number of smart meters being deployed in 2019. Why is that?

A. The Company had ordered approximately 60,000 smart meters prior to the 2018 Final Order to further the deployment of the existing 435,000 meters in the field, to keep vendors engaged, and to maintain experience with the most recent technological developments in the industry. We believe that these installations were in the best interest of our customers and are optimistic that the Commission will see the value of the investment.

Q. Will any operating systems be retired or replaced as a result of full AMI deployment?

A. The Company plans to use the AMI head-end system currently in place for the full deployment of AMI. This system has proven to meet the functional and technical specifications of Dominion Energy Virginia, and will scale to support expanded capacity in alignment with the planned rollout of smart meters. The Company will upgrade the system as needed as the deployment of smart meters progresses and as the Company enables additional AMI capabilities. Additionally, the Company plans to retire the AMR head-end and associated systems.

B. <u>Cost Estimates</u>

Q. What are the projected investment levels for AMI deployment during Phase IB of the Grid Transformation Plan?

A. Table 2 shows the Company's anticipated capital and operations and maintenance ("O&M") investments for the deployment of AMI during Phase IB. Table 2 is an excerpt from my Schedule 1. As described by Company Witness Gregory J. Morgan, the Company has committed to the investments related to AMI in Phase IB being recovered through its existing rates for generation and distribution services ("base rates").

Table 2: Phase IB Estimated AMI Capital and O&M Investment (in millions)

2019		2020		2021		Total 3 Years*	
Capital	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**
$14.9	$1.9	$71.9	$3.0	$100.3	$4.6	$187.0	$9.6

* Three year totals may not add due to rounding.

Q. What is the Company's total projected investment for AMI deployment?

A. As shown in Schedule 1, the Company anticipates an estimated $394.4 million in capital investment and $53.9 million in O&M investment for the full deployment of AMI over the 10-year GT Plan period.

Q. How did the Company develop these estimates?

A. The Company developed these cost estimates based on competitively negotiated contract pricing for various project components, along with current system information on quantity, type, and location of meters, engineered solutions for AMI field network design by deployment area, current and future internal labor rates, contracts for cellular backhaul network communications, and call center operations historical and projected costs. Our previous experience deploying AMI informed the cost estimates.

Q. Please discuss the competitively negotiated contracts you mentioned.

A. In 2011, the Company conducted a competitive bidding process for the overall AMI systems vendor, including the back office system (*i.e.*, the head-end system), network devices (*i.e.*, repeaters and collectors), network device installation, and smart meter purchases. This process resulted in the selection of Itron Networked Solutions, Inc.

("INSI"), formerly known as Silver Springs Network or SSN. In 2018, the Company went through a process with INSI to transition our AMI head-end system to the cloud, resulting in a new 10-year contract with updated pricing based on our current full deployment plans. The Master Service Agreement ("MSA") and all associated addendums, including the 2018 Statement of Work associated with conversion to the cloud, which are voluminous in nature, will be made available electronically. In addition to an updated contract, transitioning to the cloud provided the Company with cost savings associated with our network and data center infrastructure, which would have otherwise needed upgrading in order to support the full deployment of AMI. Additionally, an enhanced level of support from INSI is available now that the system is hosted in their cloud environment, providing further labor savings to the Company.

In 2019, the Company decided to separate smart meter purchasing efforts from the MSA. The Company conducted an RFP for smart meter purchasing, as described in Filing Schedule Frost, Attachment A. Based on the results of the RFP, the Company decided to use multiple meter suppliers in order to reduce the risk associated with single source supply, to ensure access to new features as they become available, and to maintain competitiveness in pricing. The Company expects to sign contracts with multiple suppliers in the coming months.

Throughout our initial deployment of AMI, the meter exchange vendor has been procured through a competitive bidding process. In 2019, the Company conducted another RFP for meter exchange contractors in order to ensure we have the best partner and most competitive pricing for full deployment. The 2019 RFP is described in Filing Schedule Frost, Attachment B. The Company expects to sign a contract with the chosen supplier in the coming months.

Q. Have these projected costs been incorporated into the CBA presented by the Company in this proceeding?

A. Yes, I have provided my Schedule 1 to Company Witness Thomas G. Hulsebosch from West Monroe, who has included them in the CBA.

C. <u>Benefits of AMI</u>

Q. What are the benefits of full AMI deployment?

A. From a foundational perspective, the over-arching benefit of full AMI deployment cannot be overstated. Nearly every investment within the Grid Transformation Plan relies directly on or is enabled by full AMI deployment. Quantitative benefits from full deployment of AMI include (i) O&M savings; (ii) avoided capital; and (iii) other benefits in the form of reduced bad debt expense, reduced energy diversion, and improved meter reading accuracy. Additional benefits also result from AMI, including reduced greenhouse gas emissions and economic development.

The full deployment of AMI, combined with the proposed customer information platform ("CIP"), also enables broad deployment of time-varying rates and enhances demand-side management ("DSM") programs, leading to energy and demand savings. Together with West Monroe, the Company has quantified these benefits and included them in the CBA to show the value of full deployment of AMI to customers.

In addition to the quantifiable benefits directly related to AMI, smart meters function as end-of-line sensors, generating essential real-time, premises-level data points. Combining these capabilities of AMI with the grid improvement investments discussed by Company Witness Robert S. Wright, Jr., will provide new and valuable insights, correlations, and trends that will, among other things, detect distribution equipment issues proactively and support circuit automation, dynamic circuit reconfiguration, and distribution asset and device monitoring.

In addition to the benefits quantified and shown in the CBA, many qualitative benefits result from the full deployment of AMI, including improved customer experience, reduced hazard exposure for employees, enhanced load forecasting, and enhanced cost of service studies. Other qualitative customer engagement benefits rely on the combination of AMI and CIP.

The benefits of full AMI deployment are perhaps best understood by looking at the functional capabilities of AMI.

Q. **What are the foundational capabilities of AMI?**

A. Foundational capabilities of AMI include: (i) remote meter reading; (ii) remote connect / disconnect; (iii) "found ons"; (iv) meter alerts; and (v) detailed energy usage data (*i.e.*, interval data). The Company has enabled these capabilities and has seen the resulting benefits in the limited population of AMI already deployed in its service territory. The benefits of these capabilities will grow with the expanded deployment of AMI across our service territory.

Q. **Please explain the remote meter reading capability of AMI and describe the associated benefits.**

A. With AMI, the Company can remotely read smart meters. As of June 30, 2019, we have completed over 78 million daily reads this calendar year. Our success rate is 99.84% for remote daily reads for this time period, meaning we get a daily read for every smart meter 99.84% of the time. AMI remote reading capability has out-performed non-AMI based reading methods. For example, for the month of May 2019, the read rates for AMR and manually read meters were 99.2% and 96.2%, respectively, meaning we get monthly reads for all AMR meters 99.2% of the time and for manually read meters 96.2% of the time.

Remote meter reading leads to O&M savings because the Company will no longer have expense associated with the people and the vehicles needed to retrieve and process readings from non-AMI meters, or re-readings when the data was missed on the first attempt. In addition, remote meter reading will lead to billing process improvements, driving out inaccuracies and process exception handling. The remote meter reading capability also leads to avoided capital; specifically, the Company will avoid the additional capital associated with AMR-related equipment and systems.

Remote meter reading also provides qualitative benefits in the form of reduced estimated bills and leads to an improved customer experience. Remote meter reading also means that fewer trucks are on the road, resulting in lower fuel usage and greenhouse gas emissions and less hazard exposure for our employees.

Q. **Please explain the remote connect / disconnect capability and describe the associated benefits.**

A. AMI allows the Company to remotely connect and disconnect electric service from most customer premises, reducing the need for meter servicing personnel to visit customer premises. With the existing population of smart meters on our system, the Company has avoided over 82,000 truck rolls to complete these types of service orders so far this year, equating to approximately 19.3% of all service orders of this type across our system. Once AMI is fully deployed, the Company anticipates that approximately 75,000 service orders of this nature will be completed remotely each month.

Remote connect / disconnect leads to O&M savings because the Company will no longer have expense associated with the people and the vehicles needed to complete these orders for non-AMI meters. This AMI capability also reduces bad debt expense. By reducing the number of calendar days between a disconnect order and its execution, the balance of past due charges and associated fees is more manageable for customers to resolve. As of June 30, 2019, year-to-date, the average customer bad debt amount for AMI customers was $378 versus $686 for non-AMI customers.

Similar to remote meter reading, remote connect / disconnect provides qualitative benefits in the form of an improved customer experience, particularly associated with move in / move out activities, reduced greenhouse gas emissions, and reduced hazard exposure for Company representatives.

Q. Please explain the "found on" capability of AMI and describe the associated benefits.

A. The Company uses AMI during storm restoration to identify premises that have had power restored but that the system still shows as an outage, which the Company refers to as "found ons." Operators can "ping" smart meters from the back office to determine if power is on and, if so, can close the outage work orders proactively.

The "found on" capability enabled by AMI leads to O&M savings because the Company will no longer have the expense associated with sending trucks to locations where power has already been restored. Data from the existing AMI footprint shows that the number of "found ons" during outage events is reduced by 80% with AMI. In addition to eliminating unnecessary truck rolls, this capability allows crews to focus on locations that actually require line work for service restoration, leading to faster overall restoration for all affected customers.

Q. Please explain the meter alerts available with AMI and describe the associated benefits.

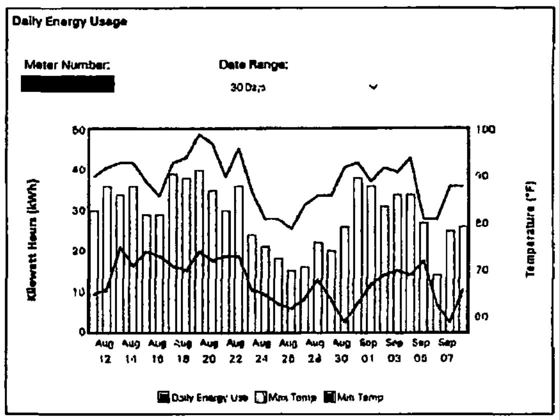
A. AMI meters generate alerts that are communicated to the head-end system, enabling back office personnel to monitor the status of power at the customer premises and generate orders for field investigation when necessary. For example, these alerts can show usage irregularities indicating unauthorized tampering with the Company's metering equipment ("energy diversion"), high internal meter temperature indicating a potential problem with Company or customer equipment, and voltage anomalies indicating operational issues.

Meter alerts lead to O&M savings in the form of reduced energy diversion. In addition to O&M savings, meter temperature alerts from smart meters have generated field visits to investigate operating conditions prior to equipment failure, which has avoided outages and potential damage to equipment and property.

Q. AMI collects and transmits detailed energy usage data (*i.e.*, at a 30-minute interval level). What benefits flow from this data?

A. Having detailed energy usage data unlocks many benefits for the Company and its customers. For customers, this data shows usage patterns, which help them to better understand their bill and to identify ways to reduce usage. For example, the Company has developed a daily graph of usage and weather-related data, which is available to those customers with AMI meters. An example is shown in Figure 2.

Figure 2: Daily Graph of Usage and Weather Data



Additionally, the Company has developed a pilot high usage alert program for its existing AMI customers where enrolled customers receive text or email alerts in near-real time when their energy usage for the day exceeds a kilowatt-hour threshold set by the customer. In the future, with the proposed CIP, the Company can offer high bill alerts, which translate usage data to estimated dollars, and prepay, which is discussed in more detail later in my testimony.

Detailed energy usage data is particularly helpful for net metering customers to understand the details of the energy received and exported at their homes, and how that translates to their net charge each month.

Combined with the proposed CIP, this data will enable the Company to broadly offer time-varying rates and will enhance DSM initiatives, which can lead to significant bill savings and reduced system costs. I will discuss both time-varying rates and DSM initiatives later in my testimony.

In addition to the benefits that detailed energy usage data provides for customers, this data also enables a host of benefits to the Company's operations, including enhancing the Company's load forecasts used in the Company's planning processes. In addition, this data enhances cost of service studies by informing the assignment of revenue and the allocation of costs.

Q. **You have discussed the foundational capabilities of AMI from which the Company has already seen the benefits. What other capabilities of AMI does the Company plan to enable or enhance in the future?**

A. In the future, the Company plans to enable or enhance: (i) remote transition to net metering; and (ii) enhanced voltage data collection.

Q. **Please explain the remote transition to net metering capability and describe the associated benefits.**

A. Today, when a customer requests to net meter, the Company must visit the premises and exchange the existing meter once the customer has installed his or her solar system and passed inspection. This is true even in the case where the new net metering customer already has a smart meter. The Company plans to implement programming to enable remote over-the-air transitioning of the existing smart meter to a net meter upon customer completion of the net metering application process.

Remote transition to net metering will lead to O&M savings in the form of reduced expense associated with the people and the vehicles needed to complete these orders. This capability will also improve the customer experience, reduce greenhouse gas emissions, reduce hazard exposure for our employees, and ultimately facilitate the integration of DERs.

Q. Please explain the enhanced voltage data collection capability of AMI and describe the associated benefits.

A. The Company plans to upgrade its AMI head-end system to include a software module associated with voltage data collection and analysis. Enhanced voltage data collection from AMI combined with the system investments discussed by Company Witness Robert S. Wright, Jr., will enable the Company to model the behavior of DERs and perform other analytics, and will enhance feeder voltage optimization. Company Witness Wright describes these benefits.

Q. As you mentioned, and as the Commission noted in the 2018 Final Order, the full deployment of AMI enables the Company to broadly offer time-varying rates. Does the Company plan to offer time-varying rates after full deployment of AMI?

A. Yes, we do. The Company is in the process of developing time-varying rates that will leverage AMI both during and after deployment. Company Witness Morgan describes the Company's plans related to time-varying rates. He also addresses the direction provided in the 2018 Final Order related to opt-in and opt-out options for such rates.

Q. Does full AMI deployment enable a prepay program?

A. Yes. Full AMI deployment combined with the new CIP will enable the Company to develop a prepay program. Prepay is a program that allows customers to make an up-front payment of their energy bill that will then be reduced over time based on their ongoing usage. Customers will receive alerts as their balance is depleted, and can take action accordingly. In other words, prepay allows customers to manage their energy usage within their budget. In the industry, prepay programs have also been shown to result in energy savings.

Q. You also mentioned that AMI will enhance the Company's DSM initiatives. Please discuss.

A. The Company intends to leverage AMI to enhance DSM initiatives in its service territory. To that end, in March 2019, the Company issued an RFP for DSM programs that included a request for information about the degree to which AMI could enhance program operations. The responses generally state that broad deployment of AMI would provide information that could be used to more effectively target the most appropriate customers for specific programs and would provide better recommendations for energy savings within any program that involves a behavioral or educational component. In addition, broad deployment of AMI would provide information that could be used to enhance the evaluation of program effectiveness and would enable, in conjunction with a new CIP, implementation of a future peak-time rebate ("PTR") program.

Q. Please explain how a PTR program would work.

A. PTR is a customer program designed to target and reduce the Company's coincident peak period. The Company would call a certain number of PTR events per year, each lasting for a certain number of hours. For example, the Company could call ten four-hour events per year to cover projected coincident peak periods. Once called, enrolled customers would receive a notification of the opportunity to reduce usage, and would earn a rebate if they reduce usage during the PTR event. Customers would not be penalized if they do not reduce usage during the event.

Q. Aside from enabling DSM programs that leverage AMI, does full AMI deployment provide other benefits to the Company's DSM initiatives?

A. Yes, AMI also provides a significant benefit to the evaluation, measurement, and verification ("EM&V") requirements of DSM programs and further supports DSM operations. For EM&V, AMI provides detailed energy usage data from each customer endpoint where smart meters are deployed. Operationally, for customers enrolled in current peak-shaving programs, AMI can provide data indicating load curtailed at the metering points of participating customers in near-real time.

In sum, the Company fully plans to leverage the full deployment of AMI to promote demand response, energy efficiency, and conservation.

D. Alternatives Considered

Q. What alternatives to the proposed deployment of AMI did the Company consider?

A. The Company considered not expediting AMI deployment, as proposed here, but continuing a slow rollout as we have done for the last several years. Given the aging state of our non-AMI meters and systems today and the amount of investment that would be needed to maintain their viability, as well as the lack of support the legacy meters and systems provide for many grid transformation initiatives, the Company felt that this was no longer a viable deployment approach. A slower rollout of AMI delays benefits and may eliminate the benefit of some avoided capital expense altogether.

Q. Did the Company consider alternative AMI systems?

A. Yes. In 2008, the Company piloted the Elster AMI system. At that time, Elster was an industry leader in AMI systems for large utilities. Elster's AMI technology was proprietary, meaning only its smart meters could be used with its network and back office system. The Company evaluated the Elster system for applications involving commercial and industrial complex meters, rugged and expansive terrain (*e.g.*, mountain, valley, rural), and dense populations (*e.g.*, urban).

The period of 2008 to 2010 saw rapid changes in AMI technology, with many new vendors entering the market. In 2010, the Company issued a request for information ("RFI") to collect information on additional AMI systems available in the market. This research resulted in the Company issuing a competitive RFP in 2011 to select new AMI systems and smart meter vendors.

During this process, the Company focused on potential vendors' relevant experience, competitive pricing, and overall capabilities. From a systems and technology perspective, technical selection criteria focused on security, network reliability, and technical performance; scalability potential; and technical and functional requirements. The Company also had a preference to select an AMI partner that would allow for diversity in smart meter suppliers, and wanted to ensure that the selected technology would not become obsolete in the medium and long term. From this RFP, the Company selected its AMI systems vendor, INSI (formerly Silver Springs Networks).

Q. Does the Company have any concerns related to the potential premature obsolescence with the selected AMI technology?

A. No. The Company is not concerned with premature obsolescence of the chosen AMI technology based on the status of AMI deployment across the United States; the research published by third parties and industry experts; and the technology features and capabilities, including specific feedback and assurances from the vendors. Company Witness Hulsebosch provides further details regarding AMI technology from an industry perspective.

E. Customer Education

Q. The 2018 Final Order required information on a transition plan to AMI, including adequate customer education. How does the Company plan to educate customers in connection with the full deployment of AMI?

A. Fully deploying AMI across the service territory provides the Company with the unique opportunity to interact directly with 2.1 million customers over the next six years. To ensure that the customer experience associated with the meter exchange is a positive one, the smart meter deployment team will be executing an outreach and education strategy, to include targeted communications to each customer prior to and during the installation phase of the new smart meter. These types of communications will be delivered through several channels, including direct mail, door hangers, social media, web, mobile, and public presentations. Customer communications will alert customers of the upcoming meter exchange, direct customers to the website for frequently asked questions, and provide options for setting an appointment for property access if needed. Examples of direct mail and door hangers can be found in my Schedules 2 and 3.

Additional post-deployment communications and outreach will also serve as a mechanism to educate and inform customers on benefits of their smart meter. Post-deployment outreach will include educating customers on tools already available to smart meter customers, and to new tools and applications as they become available. For more information on post-deployment customer education, please refer to Section VI.A.7 of the Plan Document.

Q. Is customer education related to the GT Plan necessary beyond the full deployment of AMI?

A. Yes. Because the Grid Transformation Plan is comprehensive and offers such a wide variety of benefits to all customer types, customer education appropriately extends to multiple GT Plan elements beyond smart meters. Accordingly, the Company will focus on educating customers about the entire grid transformation process, associated projects and investments, and about when and how they can fully utilize the new capabilities of the transformed distribution grid. This GT Plan-related customer education plan supplements the Company's overall efforts to educate its customers from topics ranging from available rate schedules to general energy education.

The Company's customer education plan for the GT Plan, which I sponsor, is attached to the Plan Document as Appendix F. The overarching goals for this plan are to educate customers, to raise awareness and understanding of the benefits of the Grid Transformation Plan investments, and to encourage participation in future programs and offerings to fully maximize the benefits of GT Plan. This will be accomplished by the Company's commitment to deliver concise, consistent, easy-to-understand content via multiple external communications channels, including but not limited to, website content, social media, digital and direct mail, bill inserts and newsletters, presentations and public events, video and display signage, media coverage through local and regional news outlets and interactions with the customer service organization.

F. <u>Opt-Out Policy</u>

Q. The 2018 Final Order required information on any opt-out policy related to smart meter installation. What is the Company's position related to customers opting out of the smart meter deployment?

A. The Company fully supports AMI and the benefits it provides, and believes all customers should have a smart meter. Accordingly, the Company has developed a comprehensive customer education plan. Nevertheless, the Company understands that some customers may prefer not to have a smart meter and we plan to accommodate those customers where practical if deemed necessary by the Commission.

Q. Please describe the process involved when a customer opts out of smart meter deployment.

A. When a customer opts out of smart meter installation, the Company must expend additional resources both initially and on an ongoing basis. Up front, the Company must create an opt-out version of the meter—a smart meter with the communications device removed. The Company must then install that meter. There are also administrative expenses associated with a customer's initial decision to opt out of smart meter installation, such as program administration and reporting, customer communications and account management, work order generation and scheduling, inventory management and shipping. On a monthly basis, the Company must send a meter reader to manually read the non-communicating meter.

Q. What is the Company's current opt-out practice for smart meters?

A. Currently residential customers on Rate Schedule 1 with accounts in good standing are allowed to opt out of smart meter installation upon request and at no expense. These customers receive an information packet explaining the benefits of AMI that they would forego by opting out. The customer is required to complete and return forms confirming their acknowledgement that opting out at no expense is an interim solution until the Company has an opt-out program approved by the Commission. See my Schedule 4 for details on the information packet provided when a customer requests to opt out of smart meter installation.

Q. How many customers have opted out of smart meter installation during the initial deployment of AMI?

A. As of June 30, 2019, a total of 694 customers, or 0.16% of our current smart meter population, have chosen to opt out of having a smart meter. However, opt out to date has occurred at no cost to the customer, so the Company expects the percentage of smart meter opt-out customers to decline once fees are imposed.

Q. Please describe the opt-out policy that the Company is proposing going forward.

A. Under the Company's proposed opt-out policy, residential customers taking basic service on Rate Schedule 1 with accounts in good standing will be eligible to opt out of smart meter installation upon request. The Company proposes to impose a one-time initial fee of $84.53 and an ongoing monthly fee of $29.20. These fees are intended to be revenue neutral, meaning that the Company intends to only recover the incremental costs of a customer opting out of smart meter installation. My Schedule 5 provides a draft of the proposed policy, including fees. My Schedule 6 provides a detailed breakdown of estimated up front and ongoing costs associated with customers opting out of smart meter installation. My Schedule 7 provides the proposed update to the Company's Terms and Conditions in clean and redline formats for which the Company seeks approval to implement these proposed fees. Finally, my Schedule 8 provides charts comparing the proposed fees with those imposed by other utilities for smart meter opt out.

Q. Why is the opt-out policy limited to certain residential customers?

A. Customers receiving electric service on any time-varying or demand rate and customers who generate electricity are ineligible to opt out of smart meter installation because detailed energy usage data is required to bill these customers. Allowing these types of customers to opt out of smart meter installation would require maintenance of legacy systems or significant enhancements to existing systems, which the Company has determined to be cost prohibitive.

Additionally, for customers who generate electricity, allowing these customers to opt out of smart meter installation would preclude the Company from monitoring voltage and other characteristics of electrical service at that endpoint—eliminating the end-of-line sensor benefit of smart meters.

Q. What will happen to existing opt-out customers?

A. Once approved, the Company proposes to send all current interim opt-out customers a letter informing them of the opt-out policy and associated fees. These customers will have the option to opt in to AMI at no charge, or they will be transitioned to the approved opt-out program where ongoing fees will be applied to their account from a specified date going forward. The one-time initial fee will not be billed to these interim opt-out customers because the costs have already been recovered through base rates.

II. ELECTRIC VEHICLES

Q. Mr. Frost, what is the status of the electric vehicle ("EV") market today?

A. EVs are continuing to gain market share, largely due to advancements in battery technology, additional EV model availability, declining costs, and benefits provided to customers and the environment. According to a recent Edison Electric Institute Report,[1] the number of EVs on the road in the United States is projected to reach 18.7 million in 2030, which is up from approximately 1 million EVs on the road at the end of 2018. This projection is about 7% of the 259 million cars and light trucks expected to be on U.S. roads in 2030.

In Virginia, as of December 31, 2018, there were approximately 16,500 electric vehicles registered, which is 63% growth since December 31, 2017. Of the 16,500 EVs in Virginia, approximately 11,110 were registered in the Company's service territory. The Company worked with Navigant Consulting, Inc. ("Navigant") to forecast EV adoption in the Company's service territory. Navigant's forecast shows that adoption is expected to increase in the years to come, with about 169,000 EVs projected to be in the Company's Virginia service territory in 2030. See my Schedule 9 for the full adoption forecast.

[1] See *http*://www.edisonfoundation.net/iei/publications/Documents/IEI_EEI%20EV%20Forecast%20 Report_Nov2018.pdf.

Q. Please provide an overview of the Company's overall strategy to meet this growing demand for electric transportation.

A. The Company has worked diligently with its customers, stakeholders, and peers, as well as internal and external experts, to develop a comprehensive electric transportation strategy. The strategy includes internal initiatives focused on the Company's own activities and external initiatives designed to ensure grid reliability and to be a trusted resource for customers as they transition to electric transportation. Internally, the electric transportation strategy includes offering workplace charging to employees and incorporating more EVs into the Company's fleet. Externally, the strategy includes developing rate structures and DSM programs that support off-peak EV charging, supporting the development of smart charging infrastructure, and educating.customers on electric transportation.

Q. What portion of this overall electric transportation strategy is the Company seeking approval of in this proceeding?

A. As part of the GT Plan, the Company is seeking approval of incentives for customers to adopt smart charging infrastructure. The Company is also proposing to own charging infrastructure at certain strategic locations. We will refer to these initiatives as the "Smart Charging Infrastructure Pilot Program."

Q. Before discussing the Smart Charging Infrastructure Pilot Program, please provide some additional details on other aspects of the Company's electric transportation strategy. What are some examples of the internal EV-related initiatives?

A. The Company believes that the electrification of transportation provides a number of benefits, and plans to lead by example. The Company has worked collaboratively with its corporate parent, Dominion Energy, Inc. ("Dominion Energy"), to enable many of its internal EV-related initiatives. For example, in May 2019, the Company began operating an all-electric shuttle between its Richmond-based offices. The Company will continue to add additional electric vehicles to its fleet with a goal of having 25% of its light duty fleet converted to electric or plug-in hybrid electric by 2025. As another example, Dominion Energy is installing workplace charging stations at a number of offices. These initiatives support electric transportation options for employees and will help the Company gain installation and operating experience—experience that it can use to help its customers who have similar initiatives.

Q. You also mentioned external initiatives to develop rate structures and DSM programs that support smart EV use. Please elaborate.

A. The Company is developing new, time varying rate structures to allow customers, including EV drivers, to better manage their energy usage. Company Witness Morgan addresses the status of those efforts and the Company's plan to file an experimental, voluntary time varying rate.

The Company is also evaluating DSM programs designed to encourage efficient charging of electric vehicles and shifting of electric vehicle charging load to off-peak periods. The Company solicited market input for EV-related DSM program designs in its most recent DSM RFP. The Company is currently evaluating the results from the DSM RFP in advance of its next DSM filing.

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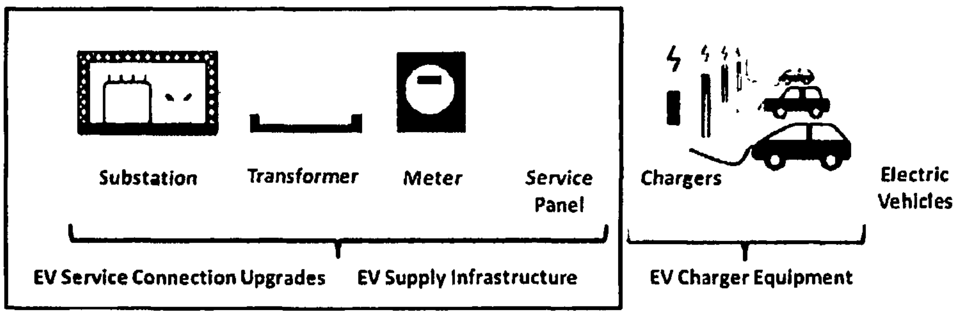
Q. Are there any other external initiatives aside from the Smart Charging Infrastructure Pilot Program that you would like to highlight?

A. Yes, the Company recently launched three other EV-related initiatives that I would like to mention. First, earlier this year, the Company launched an innovative online electric vehicle educational tool at www.dominionenergy.com/EV, which consists of a savings calculator, information on carbon reduction, a charger finder, and more. The Company launched this website to respond to customer questions and to further efforts in gaining customers' trust in the Company as an expert for electric transportation. Second, on August 29, 2019, the Company announced an innovative electric school bus initiative to replace diesel school buses with electric school buses, and then leverage the batteries using vehicle-to-grid technology. Third, the Company is evaluating a potential project to study battery storage paired with direct current fast charging infrastructure, which should provide feedback on the capabilities of the technology.

Q. Turning to the Smart Charging Infrastructure Pilot Program, please explain the proposed program.

A. The proposed Smart Charging Infrastructure Pilot Program aims to provide the Company with the data and tools necessary to understand and manage future EV charging load in furtherance of additional investments, pilots, programs, or rate designs that will support EV adoption while minimizing the impact of EV charging on the distribution grid. The Pilot Program will consist of (i) rebates for the infrastructure and upgrades, if necessary, at EV charging sites, often referred to as the "make-ready," and (ii) rebates for the smart charging equipment that enables managed charging. Figure 3 provides a diagram of these two components of EV infrastructure.

Figure 3: EV Infrastructure Diagram



Smart Infrastructure Pilot Program "Make-Ready"

Source: Edison Foundation, Plug-in Electric Vehicle Sales Forecast Through 2030 and the Charging Infrastructure Required, Figure 7

The Pilot Program will also include Company-owned charging infrastructure at strategic locations.

Q. Does Smart Charging Infrastructure Pilot Program meet the definition of an electric distribution grid transformation project under Va. Code § 56-576?

A. Yes, the Pilot Program includes investment in "electrical facilities and infrastructure necessary to support electric vehicle charging systems."

Q. Are there other policies that support the Company's strategy, including the Smart Charging Infrastructure Pilot Program?

A. Yes. The Virginia Energy Plan encourages the shift to alternative fuel transportation including electric vehicles. The Virginia Energy Plan also mentions the benefits of managed charging. The Company's Smart Charging Infrastructure Pilot Program also supports the Commonwealth's participation in the Transportation Climate Initiative by encouraging low-to-no emission vehicles in furtherance of reducing pollution from the transportation sector.

Q. As you did in the AMI section above, can you please address the Commission's four requirements the 2018 IRP Final Order as they relate to the Smart Charging Infrastructure Pilot Program?

A. Yes, I will discuss each of these items in turn. I will also discuss the proposed deployment plan developed based on the identified need, as well as the Company's plan for customer education related to the Pilot Program.

A. Existing System, Need, and Proposed Deployment Plan

Q. Please explain how EVs are typically charged.

A. Charging an EV requires plugging in to a charger that is connected to the electric grid. There are three major categories of chargers that are distinguishable by the amount of power the charger can provide, which results in different speeds of charging. Level 1 refers to use of a standard 120-volt ("V") outlet, which charges three to five miles of range per hour. Level 1 charging is ideal for overnight charging for EV owners that travel about 30 miles or fewer per day. Level 2 chargers require a higher voltage at 240V, which charges 10 to 20 miles of range per hour. Level 2 charging is ideal for workplaces, multi-family dwellings, and locations with the potential for more electric vehicles than chargers. Finally, Level 3—also known as direct current fast charging ("DC Fast Charge" or "DCFC")—can charge an EV battery to approximately 80% of capacity in 20 to 30 minutes. DCFC requires three-phase electric service and significant capacity. It is ideal for public locations to support travel over long distances.

Q. **What is the current status of charging infrastructure in Virginia?**

A. As of August 15, 2019, there were approximately 595 Level 2 and DCFC charging stations in Virginia available for public use according to the Alternative Fuels Data Center. The Company has worked with charging station companies including Tesla Motors, Electrify America, and EVgo Services to interconnect the majority of the charging stations installed in Virginia, including several sites with connected load of over one megawatt.

While the number of charging stations may seem significant, not all of these stations are available to all EV drivers. For example, many of the DCFC stations are Tesla Superchargers, which are limited to Tesla drivers. Others are installed at dealerships and are only available during business hours. There are also concerns about redundancy; many charging stations sites only have one station, meaning if the station is in use or out of service, an EV driver must wait or attempt to find another charging site. Lastly, most of the non-Tesla DCFC stations have a charging capacity of only 50 kilowatts ("kW"), which is faster than Level 2 charging, but still can require more than one hour to charge an EV battery to 80%. Newer DCFC technology is often 100 kW or higher, which can charge an EV battery much faster than 50 kW technology.

Q. **Will this charging infrastructure support the projected level of adoption of EVs in the Commonwealth?**

A. No. Industry sources attempt to project the level of charging infrastructure needed to support specific levels of adoption. To support 169,000 EVs forecasted to be in Virginia in 2030, the Department of Energy's EVI-Pro Lite tool[2] estimates the following infrastructure is needed:

- 3,778 workplace charging Level 2 plugs;
- 2,614 public Level 2 charging plugs; and
- 414 public DCFC charging plugs.

My Schedule 10, page 1 of 2, shows the results from the Department of Energy's EVI-Pro Lite tool.

Q. What are the drivers of the Smart Charging Infrastructure Pilot Program?

A. Though the level of adoption varies by source, industry experts agree that EV adoption will continue to increase, and with that adoption comes increased demand for electricity. The Company recognizes the opportunity to manage this increased demand to minimize impacts on the distribution grid and increase overall grid utilization.

Q. What is managed charging and why is it important?

A. Managed charging—also called intelligent or smart charging—allows a utility or third-party to remotely control vehicle charging by turning it up, down, or off to better correspond to the needs of the grid, much like traditional demand response programs. Managed charging is important because without awareness of the additional load resulting from EV charging and the ability to manage it, the Company loses the opportunity to reduce the impacts on the distribution grid.

As shown in Schedule 9, approximately 169,000 EVs are forecasted in the Company's Virginia service territory, requiring 558 gigawatt-hours ("GWh") of electricity annually

[2] *See* https://afdc.energy.gov/evi-pro-lite.

with a demand of 187 megawatts ("MW"). Prudently integrating and managing EV charging load on the grid is foundational to the Company's EV strategy, and vital to the Company's larger grid transformation objectives. The Company is not alone in this goal. According to the Smart Electric Power Alliance, as of May 2019, there were 38 utility-run managed charging pilots or programs for residential customers, multi-family customers, workplaces, fleets, public charging, and transit.

Q. How many rebates does the Company propose to offer through the Smart Charging Infrastructure Pilot Program, and to whom?

A. The Pilot Program will offer rebates to multi-family sites, workplace sites, public DCFC sites, and to transit agencies installing infrastructure for electric buses. The table below provides a summary of the segments, incentive amounts, and number of incentives.

Table 3: Phase IB Rebates

Segment	Rebate Amount	Number of Charging Stations During Phase IB
Multi-family	• Up to $4,071 for each dual port Level 2 networked charging station • Up to $11,140 for make-ready for each station	Up to 25 charging stations
Workplace	• Up to $2,714 for each dual port Level 2 networked charging station, • Up to $11,140 for make-ready for each stations	Up to 400 charging stations

Segment	Rebate Amount	Number of Charging Stations During Phase IB
DCFC	• Up to $36,720 for each dual port networked DCFC charging station • Up to $73,500 for make-ready for each station	Up to 30 charging stations; each customer must install at least two charging stations per site that can charge all EV types; each customer is limited to four rebates
Transit	• Up to $53,451 for each networked DCFC charging station • Up to $73,500 for make-ready for each station	Up to 60 charging stations; each customer is limited to a maximum of six rebates

To be eligible for a rebate, the site host must agree to provide charging data to the Company. The data includes, but is not limited to, time and duration of charging sessions, energy consumed, and peak demand during the charging sessions. The site host is responsible for the procurement, installation, and ownership of the EV charging station(s). The rebate amounts for the make-ready are designed to offset the cost of the electrical infrastructure and upgrades needed to install the smart charging infrastructure. The rebate amounts for the charging stations are designed to help offset the incremental cost of installing a smart charging station instead of a charging station without the ability to collect charging data and participate in managed charging.

Q. **You stated that the Company will also own charging infrastructure at strategic locations as part of the Smart Charging Infrastructure Pilot Program. Please explain.**

A. Yes. The Company is proposing to own up to four charging stations during Phase IB as part of its ongoing strategy to support electrification in the rideshare market segment. The rideshare segment refers to car services that allow a rider to use a smartphone app to arrange a ride in a privately owned or leased vehicle for a fee. Including the rideshare market segment in the Smart Charging Infrastructure Pilot Program is important for several reasons. The number of vehicle miles traveled in the rideshare market is growing exponentially. Similar to other segments mentioned above, the Company does not have the data necessary to understand charging behavior and impacts to the distribution system resulting from rideshare EV drivers and seeks to obtain this data through the Smart Charging Infrastructure Pilot Program. The Company is proposing to own four charging stations sited to strategically enable additional electric vehicles to participate in rideshare platforms, and to study the charging behavior and impacts to the distribution system resulting from rideshare EV drivers concentrated in a certain area. The Company will install and own the charging stations; procurement will be through an RFP process. The Company is engaged in ongoing discussions with the rideshare industry to identify location(s) for this initiative. Locations will be in the Company's Virginia service territory. If approved, the Company will solicit site hosts in the strategically sited areas, ensuring the stations are accessible to both rideshare drivers and the public. Site hosts at the identified locations will be responsible for electricity bills, and any fees collected from drivers for the use of the charging stations will be provided to the site hosts. The Company will not retain any fees collected from drivers for the use of the charging stations.

Q. **How did the Company determine what segments to target?**

A. The Company determined what segments to target based on its prior experience and identified areas for growth.

In 2011, the Company launched its Electric Vehicle Pricing Plans Pilot Program to learn about its residential customers' EV charging behaviors and to study the impacts of EV charging on the grid; the Commission approved that Pricing Pilot Program in Case No. PUE-2011-00014. By the conclusion of the Pricing Pilot Program in 2018, the Company had developed a general understanding of current residential charging behavior and potential impacts to the distribution system. Accordingly, the Company is not proposing to further pilot a program for residential single-family customers. Instead, the Company is evaluating managed charging programs for single-family residential customers as part of its future DSM filings.

Since the conclusion of the Pricing Pilot Program, the EV market in Virginia has continued to grow and charging technologies and behaviors have continued to evolve. Interest in EVs has expanded from largely single-family residential customers to customers in many other segments with different charging behaviors. The Company seeks to lay the groundwork to offer pilot programs for several of these segments as part of this proceeding.

Industry experts agree that the majority of EV charging happens at home. Many multi-family residential customers, such as those in apartment complexes or condominiums, are not able to install EV charging at their residence. Instead, EV charging infrastructure would need to be installed in common areas. These customers were not part of the Pricing Pilot Program; thus, the Company seeks to incent smart charging infrastructure at multi-family locations to understand charging behavior and impacts to the distribution system as adoption increases in this segment.

The second most common location for EV charging is at work. Workplace charging allows EV drivers to increase their electric driving range each day, reduces range anxiety, and provides charging options for drivers who do not have access to home charging. The Company is not aware of widespread proliferation of workplace charging stations installed in Virginia and seeks to incent smart charging infrastructure to gather the data necessary to understand workplace charging behaviors and the impacts to the distribution system for this segment.

As stated earlier in my testimony, the Company has worked with charging station companies including Tesla Motors, Electrify America, and EVgo Services to interconnect the majority of DCFC stations installed in Virginia. These charging stations are not individually metered, so the Company seeks to incent smart charging infrastructure to obtain the data necessary to understand charging behavior and impacts to the distribution system resulting from charging at DCFC stations.

Q. Please continue.

A. In addition to charging infrastructure for passenger EVs, the Smart Charging Infrastructure Pilot Program includes incentives for smart charging infrastructure for transit agencies and universities who are electrifying their bus fleets. Similar to passenger EVs, electric transit buses are cheaper to fuel and maintain than traditional diesel buses. Electric buses provide significant environmental benefits over diesel buses in the form of reduced greenhouse gas emissions and reduced transportation noise. There has also been an influx of grant funding for electric transit buses, including in Virginia. For these reasons, the Company believes electric transit bus adoption will increase significantly over the next few years. Indeed, over the last 12 months, the Company has received seven inquiries from transit agencies and universities with bus fleets regarding electric buses. The DCFC infrastructure for transit buses can range from 60 kW to 500 kW per charger. The Company does not have the data necessary to understand charging behavior and impacts to the distribution system resulting from charging electric transit buses, and seeks to obtain this data through the Smart Charging Infrastructure Pilot Program.

The Company chose to include the rideshare segment to understand charging behavior and impacts to the distribution system resulting from vehicles that have high daily vehicle miles traveled in a concentrated area. The Company also believes that including both the transit and rideshare segments in its Smart Charging Infrastructure Pilot Program will lead to more equitable future pilots, programs, or rate designs to support EV adoption while minimizing the impact of EV charging on the distribution grid.

In summary, the Company believes collecting the data necessary to understand the charging behaviors of the segments above and the potential impacts to the distribution grid will benefit all customers because it will position the Company to design programs and rate designs to encourage managed charging.

Q. Does the Company's EV strategy include options for vulnerable customers, such as low income, elderly, and disabled individuals?

A. Yes. Electrifying transit buses will extend the benefits of electric transportation to customers that may not be physically able to drive a vehicle of their own, or that may not be financially able to purchase a vehicle. The Company's incentives for multi-family communities can provide charging infrastructure for customers in affordable housing. Additionally, the Company is committed to supporting electric rideshare vehicles; many such rides start or end in low income areas, with a Richmond Times Dispatch article reporting that 58% of local Lyft rides start or end in low-income areas.[3] Encouraging EVs in the rideshare segment will help ensure the benefits of electric transportation, such as air quality improvement, are seen in low income areas, which are often areas that are impacted with disproportionally higher emissions.

Q. Why is the Company referring to this initiative as a Pilot Program?

A. The Company is referring to this initiative as a Pilot Program because it will incent installation of the required infrastructure and collect the baseline data required to be able to design managed charging programs and other customer offerings that will support EV adoption while minimizing EV charging impacts to the distribution grid.

Q. What is the deployment schedule for the Smart Charging Infrastructure Pilot Program?

A. During the fourth quarter of 2019, the Company will issue an RFP for turn-key implementation services for the Pilot Program, including enrollment, communications, rebate processing, and evaluation. The Company will also issue an RFP for the Company-owned charging infrastructure in 2019.

If approved, the Company intends to implement the Smart Charging Infrastructure Pilot Program within 60 days of approval. The Company plans collect and evaluate data obtained as part of the Smart Charging Infrastructure Pilot Program during 2020 and 2021. In late 2021, the Company anticipates requesting approval of managed charging

[3] *See* https://www.richmond.com/opinion/their-opinion/cabell-rosanelli-column-continue-richmond-s-transportation-evolution/article_57d01f4b-d097-512a-8936-aab3f5c64c39.html. *See also* https://www.forbes.com/sites/korihale/2019/04/02/lyfts-minority-drivers-level-up-in-26-billion-ipo/#23c684882983 (reporting that 44% of Lyft rides start or end in low income areas).

pilots, programs, or rate designs. Importantly, without the data collected as part of the Smart Charging Infrastructure Pilot Program during 2020 and 2021, the Company would not be able to design customer offerings specific to the charging behavior of its customers.

B. Cost Estimates

Q. What is the Company's projected investment for the Smart Charging Infrastructure Pilot Program during Phase IB?

A. Table 4 shows the Company's anticipated capital and O&M investments for the deployment of AMI during Phase IB. Table 4 is an excerpt from my Schedule 1.

Table 4: Phase IB Estimated Smart Charging Infrastructure Pilot Program Capital and O&M Investment (in millions)

2019		2020		2021		Total 3 Years	
Capital	O&M	Capital	O&M	Capital	O&M	Capital	O&M
$0	$0.4	$1.5	$5.3	$2.4	$11.4	$3.9	$17.1

Q. What is the Company's total projected investment for the Smart Charging Infrastructure Pilot Program?

A. As shown in Schedule 1, the Company anticipates an estimated $7.3 million in capital investment and $42.9 million in O&M investment over the 10-year GT Plan period.

Q. How did the Company develop these estimates and ensure they are reasonable?

A. The Company began with the EV adoption forecast for its Virginia service territory developed by Navigant, attached as my Schedule 9. Next, the Company used the Department of Energy's EVI-Pro Lite tool to estimate the charging infrastructure required to support the number of EVs in the forecast in 2030, as shown in my Schedule 10. Assuming an equal number of required charging stations will be installed per year between 2020 and 2030, the Company calculated the number of charging stations that is estimated to be installed in 2020 and 2021. This served as the basis for the number of rebates proposed in the Smart Charging Infrastructure Pilot Program. The Company believes the number of rebates is reasonable for a two-year pilot program because the number of rebates is based on the infrastructure that will likely be installed during Phase IB.

The Company gathered cost information from various sources to determine the incremental cost of the smart charging stations and the costs for construction and installation. Dominion Energy Services, Inc., issued an RFP for workplace charging stations in March 2019. The Company also solicited pricing from bidders for other types of charging stations, including DCFC stations. Filing Schedule Frost, Attachment C provides a summary of the RFP. The Company used the responses to the RFP as indicative pricing and this pricing served as the basis for the rebate amounts for the charging stations. The Company requested input from several charging station companies regarding installation costs and used this input, coupled with its experience interconnecting charging stations, as indicative pricing for make-ready. The rebate quantities and incentive amounts for the transit segment are based on input from transit agencies, transit bus manufacturers, and the Virginia Statewide Contract for electric transit buses, which was established by the Virginia Department of General Services earlier this year.[4] The costs associated with owning infrastructure were developed based on discussions with charging station equipment manufacturers.

The Company used its experience implementing other pilot programs, such as the Electric Vehicle Pricing Pilot Program, to estimate its administrative activities and costs.

C. <u>Benefits of Smart Charging Infrastructure Pilot Program</u>

Q. What are the benefits of the Smart Charging Infrastructure Pilot Program?

A. The benefits of the Smart Charging Infrastructure Pilot Program are both quantitative and qualitative, including energy and demand savings; fuel and maintenance savings for EV drivers; and reduced greenhouse gas emissions. As I noted above, Company Witness Hulsebosch supports the benefits of the Pilot Program.

D. <u>Alternatives Considered</u>

Q. What alternatives to the Smart Charging Infrastructure Pilot Program did the Company consider?

A. The Company considered a "do nothing" alternative. As shown in my Schedule 9, the approximately 169,000 forecasted in the Company's Virginia service territory in 2030 will require 558 GWh of electricity annually with a demand of 187 MW. As new EV charging load comes on to the grid, grid upgrades will likely be necessary. However, if new EV charging load comes on to the grid at times of peak demand, it can result in higher costs to absorb that load. If the Company were to "do nothing" in terms of managing new EV charging load, it could result in higher costs for the Company and its

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[4] *See* https://logi.epro.cgipdc.com/External/rdPage.aspx?rdReport=Public.Reports.Report9008_Data&lnk From=New.

customers, such as the need for additional distribution upgrades or the need for more fast ramping peaker plants.

In order to fully and prudently support EV adoption, the Company believes that investments in managed EV charging are needed today—in the earlier years of EV adoption to allow the Company the necessary time to implement supporting technologies and infrastructure, and to adapt workforce skills to support them. This includes deploying and learning how to validate methods and processes for managed charging in a diversity of customer scenarios. As a result, we believe it is necessary to lay the groundwork for managed charging today to enable expanded EV adoption in a way that sustains grid reliability and safety.

Q. Did the Company consider any other alternatives?

A. The Company developed the Pilot Program based on the forecasted approximately 169,000 EVs in the Company's service territory in 2030, but also evaluated the low and high forecast scenarios provided by Navigant.

The low scenario provided by Navigant would have a smaller impact on the Company's distribution system; however, the risk of doing nothing still remains. If the Company assumes the low scenario and actual adoption of EVs is higher, and if non-networked, uncontrollable charging stations without the ability to provide data or participate in managed charging are installed, the Company will not have awareness of the resulting EV charging load or the ability to manage it. The Company believes it would be unlikely for customers to remove their non-networked, uncontrollable charging stations shortly after installing them to install networked controllable charging stations to take advantage of managed charging programs. The Company determined the high scenario was not an appropriate assumption for a pilot program as proposed in Phase IB.

E. Customer Education

Q. Please explain the education and communications that will accompany the Smart Charging Infrastructure Pilot Program.

A. The education and communications that will accompany the Smart Charging Infrastructure Pilot Program consist of communications to solicit customer enrollment and ongoing communications with participants. Customer enrollment solicitation will include web content, social media, and other outreach. Ongoing communications with participants will include continued education on managed charging, surveys to obtain customer feedback, and customer service associated with participation in the Pilot Program. For additional discussion on customer education, see Section VI.A.7 of the Plan Document.

III. CONCLUSION

Q. Mr. Frost, please summarize your testimony.

A. My testimony covered two components of the Company's Grid Transformation Plan, the full deployment of AMI and the Smart Charging Infrastructure Pilot Program.

Starting first with the Smart Charging Infrastructure Pilot Program, the Company proposes to offer rebates to incent the infrastructure necessary for managed charging, also referred to as "smart" charging. In addition, the Pilot Program includes Company-owned charging at strategic locations. The information gained from the proposed Pilot Program will provide the Company with the data and tools necessary to understand and manage future EV charging load in furtherance of additional pilots, programs, or rate designs that will support EV adoption while minimizing the impact of EV charging on the distribution grid.

Turning to AMI, the Company proposes to fully deploy smart meters AMI across its Virginia service territory. Through AMI, the Company can remotely read smart meters and send commands, inquiries, and upgrades to individual smart meters, minimizing the need for field visits. From a foundational perspective, the over-arching benefit of full AMI deployment cannot be overstated. Nearly every investment within the Grid Transformation Plan relies directly on or is enabled by full AMI deployment. Benefits from full deployment of AMI include operational efficiencies and increased information and control of the electric grid for the Company; customer benefits in savings, convenience, information, and reduced energy consumption; and additional benefits in reduced greenhouse gases.

Q. **Does this conclude your pre-filed direct testimony?**

A. Yes, it does.

Appendix A

BACKGROUND AND QUALIFICATIONS
OF
NATHAN J. FROST

Nathan J. Frost graduated from James Madison University with a Bachelor of Business Administration in Finance. He joined Dominion Energy in 2005 and has held numerous positions in the areas of Enterprise Risk Management, Producer Services, Investor Relations, and Power Delivery. Mr. Frost was most recently Manager – New Technology and Renewable Programs for Dominion Energy Virginia, and assumed his current position as Director – New Technology and Energy Conservation for Dominion Energy Virginia in January 2019. In this position, Mr. Frost is responsible for delivering demand side management and advanced metering solutions for the Company. In addition, he is responsible for developing renewable energy programs and integrating new technologies such as solar distributed generation and electric vehicles with Dominion Energy Virginia's regulated service territory.

Mr. Frost has previously submitted testimony before the State Corporation Commission of Virginia.

Line No. (A)	Description (B)	2019 Yr 1 (C)	2020 Yr 2 (D)	2021 Yr 3 (E)	3 Yr Total Sum (C)-(E) (F)	10 Yr Total Sum (C)-(L) (G)
1	**Summary of AMI Capital Costs**					
2						
3	Meter Deployment Labor Costs	$ 4,817,192	$ 14,746,306	$ 20,868,194	$ 40,431,692	$ 93,908,198
4	Meter & Meter Hardware Costs	$ 7,648,555	$ 50,682,244	$ 70,583,342	$ 128,914,140	$ 261,133,576
5	Network Materials & Installation Costs	$ 826,398	$ 1,446,515	$ 2,953,638	$ 5,226,551	$ 11,370,152
6	Licensing & Communications	$ 262,448	$ 1,690,168	$ 2,432,637	$ 4,385,254	$ 9,451,670
7	Capability Development/Enhancement	$ 1,299,671	$ 3,292,951	$ 3,445,551	$ 8,038,173	$ 18,567,744
8						
9	Total AMI Capital Costs	$ 14,854,264	$ 71,858,184	$ 100,283,362	$ 186,995,810	$ 394,431,340
10						
11						
12	**Summary of AMI O&M Costs**					
13						
14	Internal Labor, Vehicle, & Travel	$ 609,608	$ 968,088	$ 900,958	$ 2,478,654	$ 5,292,594
15	Hardware/Software Maintenance, Communications, & Call Center	$ 1,313,783	$ 2,056,922	$ 3,721,143	$ 7,091,848	$ 48,603,942
16						
17	Total AMI O&M Costs	$ 1,923,391	$ 3,025,011	$ 4,622,101	$ 9,570,502	$ 53,896,535
18						

Key Inputs	
Depreciable life	11.4yrs
3yr Total AMI Meter Deployment Count (2019-2021)	985,639
6yr Total AMI Meter Deployment Count (2019-2024)	2,116,548

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Summary of Stakeholder Engagement & Customer Education Capital Costs					
2						
3						
4	Total Stakeholder Engagement & Customer Education Capital Costs	$ -	$ -	$ -	$ -	$ -
5						
6						
7	Summary of Stakeholder Engagement & Customer Education O&M Costs					
8						
9	Collateral & Events	$ 40,000	$ 1,335,500	$ 1,558,860	$ 2,934,360	$ 9,433,106
10	Internal Dominion Labor	$ -	$ 100,000	$ 200,000	$ 300,000	$ 1,700,000
11						
12	Total Stakeholder Engagement & Customer Education O&M Costs	$ 40,000	$ 1,435,500	$ 1,758,860	$ 3,234,360	$ 11,133,106
13						

Company Exhibit No. ___
Witness: NJF
Schedule 16
Page 2 of 3

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Summary of Transportation Electrification Capital Costs					
2						
3	Rideshare Charging Station Make Ready and Equipment ($)	$ -	$ 699,700	$ -	$ 699,700	$ 2,798,800
4	Transit Bus Charging Station Make ready ($)	$ -	$ 420,000	$ 1,680,000	$ 2,100,000	$ 2,100,000
5	Public DC Fast Charge Station Make Ready ($)	$ -	$ 350,000	$ 700,000	$ 1,050,000	$ 2,450,000
6						
7	Total Transportation Electrification Capital Costs	$ -	$ 1,469,700	$ 2,380,000	$ 3,849,700	$ 7,348,800
8						
9						
10	Summary of Transportation Electrification O&M Costs					
11						
12	Program Management ($)	$ 393,500	$ 1,167,842	$ 1,329,881	$ 2,891,223	$ 17,163,695
13	Single-Family Residential Program Costs					
14	Single-Family Residential Charger - Equipment Rebate Expense ($)	$ -	$ 116,375	$ 148,375	$ 264,750	$ 1,329,375
15	Single-Family Residential Charging Program O&M Expense ($)	$ -	$ 102,792	$ 162,504	$ 265,296	$ 6,527,793
16	Multi-Family Residential Program Costs					
17	Multi-Family Residential Charging Station - Make-Ready/Equipment Rebate Expense ($)	$ -	$ 152,110	$ 228,165	$ 380,275	$ 1,521,100
18	C&I Program Costs					
19	Workplace Charging Station - Make-Ready/Equipment Rebate Expense ($)	$ -	$ 1,939,560	$ 3,602,040	$ 5,541,600	$ 5,541,600
20	Public Transit Program Costs					
21	Transit Bus Charging Station - Make-Ready/Equipment Rebate Expense ($)	$ -	$ 1,103,406	$ 4,413,624	$ 5,517,030	$ 5,517,030
22	Public DC Fast Charging Program Costs					
23	Public DC Fast Charge Station - Make-Ready Rebate Expense ($)	$ -	$ 752,200	$ 1,504,400	$ 2,256,600	$ 5,265,400
24						
25	Total Transportation Electrification O&M Costs	$ 393,500	$ 5,334,285	$ 11,388,989	$ 17,116,774	$ 42,865,994
26						

Key Inputs	
Asset Life	11 yrs
Single-Family Residential Chargers (cumulative in Year 10)	44,268
Steady State Multi-Family Charging Stations	100
Steady State Workplace Charging Stations	400
Steady State Transit Bus Charging Stations	60
Steady-State DC Fast Charging Stations	70
Steady-State Rideshare Charging Stations	16