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October 11, 2018

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF ITS CLEAN ENERGY FUTURE-ENERGY CLOUD ("CEF-EC") PROGRAM ON A REGULATED BASIS

BPU Docket No. ________

VIA BPU E-FILING SYSTEM & HARD COPY

Aida Camacho-Welch, Secretary of the Board
Board of Public Utilities
44 South Clinton Avenue, 9th Floor
Trenton, New Jersey 08625

Dear Secretary Camacho-Welch:

Enclosed for filing are the original and two copies of the Verified Petition of Public Service Electric and Gas Company ("PSE&G" or the "Company") in the above-entitled matter, along with the attachments and appendix thereto. PSE&G originally filed this matter with the Board of Public Utilities ("BPU" or the "Board") on September 26, 2018, along with its Clean Energy Future – Energy Efficiency ("CEF-EE") and Clean Energy Future – Electric Vehicle and Energy Storage ("CEF-EVES") Programs. However, per the BPU's request, PSE&G is now filing these three Clean Energy Future Programs separately, with their own petitions and docket numbers.

In support of PSE&G's CEF-EC Petition, attached and filed herewith are the Direct Testimonies and Schedules of the following witnesses.

Attachment	**Witness**	**Area of Responsibility**
1	Gregory C. Dunlap, Vice President, Customer Operations, PSE&G	The Energy Cloud, including advanced metering infrastructure
2	Donna M. Powell, Assistant Controller – PSE&G, PSEG Services Corporation	Stranded asset costs associated with removed analog electric meters

3	Stephen Swetz, Senior Director, Corporate Rates and Revenue Requirements, PSEG Services Corporation	Revenue requirements, cost recovery methodology, and rate design

PSE&G respectfully requests that the Board retain jurisdiction over this CEF-EC filing. Copies of the Petition and supporting documentation will be served upon all entities legally required to be noticed.

We look forward to the opportunity to actively participate in these upcoming proceedings and putting New Jersey on a path to a Clean Energy Future.

Respectfully submitted,

Matthew Weissman

Matthew M. Weissman

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STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF ITS CLEAN ENERGY FUTURE- ENERGY CLOUD PROGRAM ON A REGULATED BASIS	))))))	**P E T I T I O N** BPU Docket No. _________

I. INTRODUCTION

Public Service Electric and Gas Company ("PSE&G" or the "Company"), a corporation of the State of New Jersey, having its principal offices at 80 Park Plaza, Newark, New Jersey, respectfully petitions the New Jersey Board of Public Utilities ("Board" or "BPU") pursuant to N.J.S.A. 48:2-21, N.J.S.A. 48:2-21.1, N.J.A.C. 14:3-2A, and any other statute or regulation the Board deems applicable, as follows:

1. Petitioner is a public utility engaged in the distribution of electricity and the provision of electric Basic Generation Service ("BGS"), and the distribution of gas and the provision of Basic Gas Supply Service ("BGSS"), for residential, commercial, and industrial purposes within New Jersey. PSE&G provides service to approximately 2.2 million electric and 1.8 million gas customers in an area having a population of approximately six million people, which extends from the Hudson River opposite New York City, southwest to the Delaware River at Trenton and south to Camden, New Jersey.

2. PSE&G is subject to regulation by the Board for the purposes of setting its retail distribution rates and to assure safe, adequate, and reliable electric distribution and natural gas distribution service pursuant to N.J.S.A. 48:2-21 *et seq*.

3. Through this Petition and the accompanying schedules and testimonies, PSE&G seeks BPU approval for The Clean Energy Future – Energy Cloud Program ("CEF-EC

Program") which, together with two other programs that PSE&G is filing at this time ("Other Programs"), under separate Petitions and docket numbers, forms the basis for a clean and resilient energy future. The CEF-EC Program, the foundation of which is the deployment of advanced metering infrastructure ("AMI") throughout the Company's electric service territory, will be the technological platform that strengthens and modernizes the electric grid and the PSE&G customer experience.

4. This Program, along with the Other Programs, will form a Clean Energy Future for New Jersey. This EC Program in particular furthers the State's goals by, among other benefits: (a) lowering energy consumption and customer bills; (b) reducing greenhouse gas emissions; (c) making the electric grid more reliable, resilient, and safe; and (d) enabling a number of customer, community, and company smart energy capabilities. This EC Program, taken together with the Other Programs will allow New Jersey to take the first steps toward becoming a leader in the development of a Clean Energy Future.

II. THE CEF-EC PROGRAM

A. Background

5. PSE&G submits the CEF-EC Program pursuant to the Board's rules on Infrastructure Investment Programs ("IIPs"), *N.J.A.C.* 14:3-2A. Consistent with the IIP regulations, the CEF-EC Program proposes infrastructure investments to enhance the safety, reliability, and resiliency of the electric grid through the deployment of AMI throughout PSE&G's electric service territory.[1] As set forth in more detail below and in the Direct Testimony of Gregory C. Dunlap, this is the appropriate time for PSE&G to install advanced electric meters because:

[1] PSE&G at this time is not seeking to install AMI in its gas service territory.

- AMI enhances storm restoration efforts at a time when the northeastern area of the country faces increasingly more challenging weather events;
- AMI offers significant value through customer benefits and operational savings, which will be realized more quickly given PSE&G's accelerated five-year deployment plan;
- New Jersey is considerably behind almost the entire country with respect to AMI;
- PSE&G is expecting to replace nearly one third of its electric meter population in the near future (~700,000 meters) given their length of service; and
- The price of an AMI meter is now comparable to the price of an automated meter reading ("AMR") device.

6. PSE&G anticipates the CEF-EC Program will be deployed over a five-year period (2019-2024), subject to Board approval. The CEF-EC Program proposes estimated investment of approximately $721 million and operations and maintenance ("O&M") costs of $73 million, from 2019 to 2024. Appendix A attached to this Petition sets forth the location in this filing of all minimum filing requirements per the Board's IIP regulations.

7. PSE&G also submits the CEF-EC Program in accordance with Recommendation #12 of Board Staff's investigative report regarding the performance of the state's electric distribution companies ("EDCs") during the March 2018 Nor'easters (the "Investigative Report"). Recommendation #12 of the Investigative Report requires PSE&G and the two other EDCs currently without AMI to "submit a plan and cost benefit analysis for the implementation of AMI. The EDCs' plans should focus on the use and benefits of AMI for the purpose of reducing customer outages and outage durations during a major storm event."[2] A cost-benefit analysis and the uses and benefits of AMI for the purpose of reducing outages (as well as other

[2] *See Order Accepting Staff's Report Requiring Utilities to Implement Recommendations*, BPU Docket No. EO18030255, (July 25, 2018), at p. 13.

CEF-EC Program benefits) are set forth below and in Mr. Dunlap's testimony.

B. Use Case Overview

8. The CEF-EC Program in total will consist of 70 applications or "use cases." This filing seeks BPU approval of the initial phase of the CEF-EC Program, referred to in this filing as "Release 1," that features 22 of the 70 use cases. These 22 use cases focus on customer engagement, network operations and planning, and new utility products and services. Release 1 will establish the foundation for the CEF-EC Program, including the platform that is comprised of advanced electric meters as well as communications and back-office systems.

9. The table below summarizes the 22 use cases that are part of Release 1:

Use Case #	Use Case Name	Use Case Overview and Value
1	Enhanced Customer Engagement and Communications	A set of customer-benefiting functions and analytic applications that provide visualizations and information to customers, through bi-directional communications channels, including mobile and web portals
2	Rate Analyzer and Comparator	The ability to analyze customers' usage profile and provide rate options that would fit that profile and meet customer needs for green outcomes, reduced bills, etc.
3	Usage and Bill Alerts, Saving Tips, Interactive Bill Presentment	Alerts that would be set by the customer and PSE&G to warn or notify customers of usage outside normal parameters, tips within their current rates to reduce bills, etc.
4	Interactive Energy Demand and Bill Management	Customer analytics capabilities that allow the customer to interrogate their energy and billing profile with the aim of the customer becoming informed and engaged, and then be able to leverage the use cases above to make required changes
5	Customer Segmentation and Behavioral Analysis	Provides the ability to develop highly targeted customer segmentation models based on more granular usage data
6	Customer Power Quality	Allows PSE&G to obtain voltage, load, and alert data directly from the meter to analyze customer power quality issues
7	Customer Energy Efficiency Programs	Data that gives the customer the ability to make more educated energy efficiency-related decisions, and change energy consumption habits
8	Customer Service and Call Center Performance	Enables the use of broader range of information to increase call center personnel knowledge, improve service, improve customer satisfaction, and lower customer costs

9	Customer DER/PV/EV	Services and systems that will use data to help assist customers with distributed energy resources or “DER” (*i.e.*, solar, EV, energy storage) installations, and the management of any power quality issues that occur as a result of variable DER load
10	Customer Device Safety	Enhances customer safety by using data -- such as alerts and voltage data -- to detect safety issues relating to customer meters and power connections, and provide safety alerts to customers and PSE&G (*e.g.*, Hot Sockets)
11	Sensor, Network, and Data Operations	Back office processes and systems that manage the initial infrastructure deployment and the ongoing and updated meter operations business function
12	Automated Move in/Move out	Automation of service related to customer requested move-in and move-outs
13	Remote Disconnect/ Reconnect	Automation of service related to the reconnecting and disconnecting of customers
14	Next Generation Meter-to-Cash	Enables PSE&G to optimize and re-invent its meter-to-cash processes and drive out inefficiencies, increase service, and reduce costs
15	Network Connectivity Analysis	Advanced meters can extend the network model and enable a high level of accuracy of connections and phasing, which in turn results in better planning and operations performance
16	Outage Detection and Analysis	Uses outage data from operations systems and advanced meters to identify and verify possible outage locations, as well as identify network sections and specific customers (and numbers) that are without power
17	Outage Response Notification/Estimated Time of Restoration (ETR)	Uses outage data to calculate and communicate reasonable, more accurate, and acceptable outage status and ETR to customers
18	Voltage Monitoring and Analysis	Using data and other network data sources, voltage readings are captured, visualized, and system-wide analysis is run to determine locations where voltage violations exist both above and below nominal voltage
19	Asset Load/Phase Management, Balancing and Power Analysis	Provides information that helps determine areas of overloading of assets on the electric system, plan the response to major events, execute asset balancing, and customer load curtailment
20	Load Profiling and Forecasting	Enhances load profiles and forecasts by using data in combination with network, customer billing, or other data to perform more detailed usage analysis
21	Distribution Losses	Distribution losses can be identified and remedied by comparing the end-point meter usage data with usage data at the distribution entry point (substation)
22	Revenue Protection and Assurance	This use case will leverage advanced meter consumption, as well as voltage and alert data, to detect energy theft and meter tampering

10. In accordance with IIP project requirements, the CEF-EC Program through these use cases promotes the safety, reliability, and resiliency of the electric grid, and consists of non-revenue producing infrastructure. *N.J.A.C.* 14:3-2A.2(a)(1)-(2). The IIP rules consider "[e]lectric distribution automation investments, including, but not limited to…voltage and reactive power control [and] communications networks" to be projects eligible for IIP treatment. *N.J.A.C.* 14:3-2A.2(b)(4). The CEF-EC Program establishes the communication network that enables the electric distribution automation described in the use cases. Moreover, Use Case #18 gives PSE&G the opportunity to determine with better efficiency where voltage violations exist, both above and below nominal voltage. Thus, the CEF-EC Program is within scope of the IIP rules.

C. <u>CEF-EC Program Benefits and Costs</u>

11. The CEF-EC Program is cost effective. During the deployment and benefit realization period of nearly 20 years (*i.e.*, 2019-2037, subject to BPU approval), the CEF-EC Program will deliver an estimated $1.73 billion of customer and operational benefits, versus $794 million of costs, for total net benefits of $937 million. Qualitative benefits are not included in this calculation, but are instead discussed in the EC Business Case. *See* Schedule GD-CEF-EC-2.

12. The customer benefits will be realized via: (a) increased participation in existing Time of Use rate; (b) improved storm response (including up to an estimated 2% improvement in reliability metrics, specifically System Average Interruption Duration Index or "SAIDI"); (c) reduction in use from inactive accounts; (d) reduction in write-offs; (e) avoided energy theft; and (f) recovered line loss due to slow meters.

13. With respect to operational benefits, the remote data and connection capabilities provided by the CEF-EC Program will eliminate the need for nearly all manual meter reads, as well as certain call center and field collection responsibilities.[3] These capabilities will also increase the data accuracy of meter reads from 91% to at least 99%, thereby reducing the amount of estimated reads, increasing bill accuracy, and lowering customer complaints. AMI will also help the Company improve in the customer service metrics agreed upon in PSE&G's 2009/2010 base rate case; for example, meter reads on cycle, customer rebills, and BPU complaints.

14. Savings will also be achieved due to reduced workloads and truck rolls; more specifically, remote and instantaneous disconnect and reconnect activities, avoided customer power quality visits and investigation, and outage management improvement. These benefits will free up field personnel, thereby improving PSE&G's performance in another customer service metric agreed upon in its 2009/10 base rate case, *i.e.*, customer service appointments met.

15. The CEF-EC Program will also result in environmental benefits, helping to put New Jersey back on track to satisfy the NJGWRA's GHG reduction standards. This phase alone of the CEF-EC Program will result in the reduction of carbon dioxide emissions by 2,761 tons through fewer truck rolls.

D. <u>Electric AMI Deployment</u>

16. PSE&G will install approximately 2.2 million advanced (or "smart") meters throughout its electric service territory over the course of a five-year period, beginning in 2019. PSE&G's entire customer base will receive an advanced electric meter (*i.e.*, residential, commercial, and industrial customers). PSE&G proposes that residential customers seeking to

[3] PSE&G's intention is to offer employment elsewhere in the Company for any permanent employee that is displaced because of AMI.

opt-out of an advanced meter pay a $20.00 monthly fee for meter reading services. Residential customers seeking to replace an installed AMI meter with a non-AMI meter will be assessed a one-time fee of $45.00. Commercial and industrial customers will not be permitted to opt out of an AMI meter.

17. As set forth in more detail in Mr. Dunlap's testimony, the Company has created a communications strategy to keep customers informed at each step of the AMI implementation, *i.e.*, the pre-deployment, deployment, and post-deployment stages. The communications strategy addresses objectives, key messages, audiences, communication channels, and supporting materials. (*See* Schedule GD-CEF-EC-3).

18. With respect to Recommendation #12 of the Investigative Report, the CEF-EC Program -- and its AMI enabling capabilities -- will allow PSE&G greater visibility of its distribution system. PSE&G system operators will have the ability to "see" the status of the network down to the customer meter level, including which customers are still without power during an outage. This increased level of visibility will allow PSE&G to make more informed restoration decisions, which will lead to better resiliency and customer service, and fewer truck rolls.

19. CEF-EC Program restoration improvements will include faster identification of "nested outages" (*i.e.*, secondary outages that are not identified or fixed during initial restoration activities). Quicker identification can reduce outage periods, as well as shorten the tail end of major storm event restoration activities. Without the CEF-EC Program, PSE&G is dependent on customers calling to report an outage, adding significant delay in restoration and customer frustration.

20. The CEF-EC Program can also assist with the ETR communications-related

concerns Board Staff identified in the Investigative Report. More specifically, Recommendation #15 calls for PSE&G to provide an ETR for each of its four operating divisions within 24 hours after a weather event or other major event has exited its service territory.[4] Use Case #17 incorporates analytics and automation to improve PSE&G's ETR calculations and communications.

21. PSE&G respectfully submits that now is the time for the Company -- the state's largest electric utility -- to install electric AMI. New Jersey has fallen behind nearly the entire nation with respect to AMI and the customer and operational benefits it provides. According to a December 2017 report from the Federal Energy Regulatory Commission, the number of advanced meters in the United States grew ten-fold from 2007 to 2015.[5] Yet, at the end of 2016, New Jersey had less than 50,000 advanced meters deployed, and ranked 47th out of 50 states in terms of advanced meter penetration.[6] Only three states other than New Jersey -- West Virginia, New York, and Rhode Island -- had less than 1% advanced meter penetration and New York, with its Reforming the Energy Vision initiative,[7] will have widespread AMI adoption in short order. A review of 2016 U.S. Energy Information Administration data reveals that the number of AMI meters deployed nationwide had increased to more than 70 million,[8] which accounted for approximately 47% of utility customers. However, in September 2018, no PSE&G residential

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4 *See* the July 25, 2018 Order, *supra*, at p. 14.

5 https://www.ferc.gov/legal/staff-reports/2017/DR-AM-Report2017.pdf (at p. 4)

6 https://www.eia.gov/electricity/data/eia861/

7 https://static1.squarespace.com/static/576aad8437c5810820465107/t/5aec725baa4a99171e5890d4/1525445212467/REV-fm-fs-1-v8.pdf

8 https://www.eia.gov/tools/faqs/faq.php?id=108&t=3

customer has an advanced meter.[9]

22. It is also the appropriate time for PSE&G to install AMI given that approximately 700,000 of its electric meters (almost one-third of the Company's entire electric meter population) will soon be replaced given the length of time that they have been in service. The cost of an AMI meter is now comparable to that of an AMR meter (PSE&G's current replacement meter), and analog (mechanical) meters are no longer being manufactured. Replacement of aged, analog meters with non-AMI meters would add stranded costs -- as AMI is the present and future of metering technology -- and merely replace one meter with limited functionality with another. Furthermore, the timing for electric AMI deployment coincides with full deployment of AMR in PSE&G's gas service territory, meaning customers who receive electric and gas service from the Company would benefit from automated meter reading for both services.

23. PSE&G is aware of the moratorium on EDCs filing for "pre-approval" of AMI that the Board outlined in its August 23, 2017 Order authorizing RECO to proceed with its AMI program.[10] However, as the BPU and Board Staff implicitly recognized as part of the Investigative Report, AMI is a key component to improving resiliency and customer satisfaction. Without AMI, customers face longer restoration times and increased frustration. Moreover, AMI -- with the near real-time usage data it provides to customers in the literal palms of their hands -- can reduce energy consumption and lower customers' utility bills, consistent with the policies underlying the Clean Energy Law, enacted by the Legislature well after the AMI moratorium

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[9] PSE&G is aware of the Rockland Electric Company ("RECO") AMI initiative to install approximately 72,000 advanced meters throughout its electric service territory. Even considering the RECO AMI Program, New Jersey remains well behind the vast majority of the nation with respect to AMI.

[10] *See* Decision and Order, *In the Matter of the Petition of Rockland Electric Company for Approval of an Advanced Metering Program; and for Other Relief*, BPU Docket No. EO16060524, p. 24 (August 23, 2017 Order).

was announced. AMI also benefits the environment by reducing the vehicle emissions caused by unnecessary truck rolls. Thus, AMI deployment is a matter of sound public policy and in the best interests of New Jersey. This is perhaps why -- in the colloquy surrounding the Investigative Report at the BPU's July 25, 2018 agenda meeting -- Commissioner Chivukula appropriately questioned Staff as to whether it should assess the moratorium's continued viability.[11] At a minimum, PSE&G's deployment of AMI across its vast and diverse service territory can provide the BPU with additional information -- beyond that provided by RECO's program -- about AMI deployment in the state, including in its most populated and urban areas, as well as the benefits AMI can provide to low income customers. PSE&G submits that the moratorium should be lifted.

E. CEF-EC Program Cost Recovery

24. PSE&G is proposing a cost recovery mechanism for the CEF-EC Program that is consistent with the BPU's IIP regulations, as addressed in detail in Mr. Swetz's CEF-EC testimony.

25. The cost recovery method will involve the potential of semi-annual base rate adjustment filings, consistent with the IIP regulations and the same approach used for PSE&G's Energy Strong (electric) and GSMP II programs. The proposed schedule for these potential filings is shown in the chart below:

Potential EC Rate Roll-in Schedule

Roll-in #	Rates Effective	Initial Filing	Investment as of	True-up Filing
1	6/1/20	12/31/19	2/29/20	3/15/20
2	12/1/20	6/30/20	8/31/20	9/15/20
3	6/1/21	12/31/20	2/28/21	3/15/21
4	12/1/21	6/30/21	8/31/21	9/15/21

[11] Transcript, July 25, 2018 Board Agenda Meeting, BPU Docket No. EO18030255, Item 6A, page 33, lines 9-15.

5	6/1/22	12/31/21	2/28/22	3/15/22
6	12/1/22	6/30/22	8/31/22	9/15/22
7	6/1/23	12/31/22	2/28/23	3/15/23
8	12/1/23	6/30/23	8/31/23	9/15/23
Final	1/31/24	7/31/24	3/31/24	4/15/24

26. Since the IIP rules limit each base rate adjustment request to a minimum investment level of 10 percent, PSE&G projects that its filings for such increases will be less often than the potential semi-annual filings and that the first base rate adjustment filing in the CEF-EC Program will be in December 2020.

27. Consistent with GSMP, GSMP II, Energy Strong, and the Company's Energy II Strong filing, PSE&G proposes that the costs to be included in rates will include: depreciation/amortization expense providing for the recovery of the invested capital over its useful book life; return on the net investment, where net investment is the capital expenditures less accumulated depreciation/amortization, less associated accumulated deferred income taxes; and the impact of any tax adjustments applicable to the CEF-EC Program. The return on net investment will be based upon a WACC. The Company proposes a WACC for the CEF-EC Program based upon the most recent WACC for base rates approved by the Board. Since the 2018 Rate Case is still pending and PSE&G anticipates approval of that matter before the first CEF-EC Program rate adjustment filing, the WACC utilized for forecasting purposes is the WACC proposed in the 2018 Rate Case. PSE&G proposes that any change in the WACC authorized by the Board in the pending or any subsequent base rate case be reflected in the subsequent revenue requirement calculations.

28. BPU Staff and Rate Counsel will have an opportunity to review each rate adjustment filing to ensure that the revenue requirements and proposed rates are being calculated in accordance with the BPU Order approving the CEF-EC Program and the IIP rules. The

changes to base rates made through these rate adjustment filings would be subject to refund based upon a Board finding that PSE&G imprudently incurred capital expenditures in its implementation of the CEF-EC. The actual prudence of the Company's expenditures in CEF-EC Program will be reviewed as part of PSE&G's subsequent base rate case(s) following the rate adjustments. This is identical to the approach under the Energy Strong, GSMP, and GSMP II programs, and the Board's IIP regulation at *N.J.A.C.* 14:3-2A.6(e). The Company proposes that it will file its subsequent base rate case no later than five years after the commencement of the CEF-EC Program.

29. In addition to limiting the base rate adjustment requests to a minimum investment level of 10 percent of the total program investment, PSE&G is also proposing to limit the amount of investment to be included in the rate base adjustments by an earnings test. Consistent with the IIP regulations, if the Company exceeds the allowed ROE from its last base rate case by 50 basis points or more for the most recent 12-month period, the pending base rate adjustment shall not be allowed for the applicable filing period. Details regarding application of the earnings test are set forth in Mr. Swetz's testimony.

30. Based upon the forecasted rates shown in Schedule SS-CEF-EC-3, the typical annual bill impacts for a residential customer as well as rate class average customers compared to rates as of September 8, 2018 are set forth in Schedule Attachment 4.[12] Based on the estimated roll-in revenue requirements provided in Schedule SS-CEF-EC-2, the initial annual impact of the proposed rates for the first roll-in period to the typical residential electric customer who uses 750 kilowatt-hours in a summer month and 7,200 kilowatt-hours annually is an increase of $5.52 or approximately 0.45%. The maximum cumulative impact (impact from the

[12]The bill impacts assume that customers receive commodity service from PSE&G under the applicable BGS rate.

CEF-EC Program) on the typical residential electric customer is an average annual increase of approximately 3.29% or about a $3.38 increase in their average monthly bill.

31. PSE&G seeks approval to defer as a regulatory asset the stranded costs associated with the removal of analog meters that have not fully depreciated. The net book value of PSE&G's electric meters as of June 30, 2018 is $219 million. That amount will continue to decline over the next several years as the meters are depreciated, with the remaining investment stranded when those meters are replaced by AMI meters. The Company will seek to recover these stranded costs over a fixed, five-year period following PSE&G's next base rate case. The Direct Testimony of Donna M. Powell provides more detail regarding this proposal.

32. Deployment of the CEF-EC Program requires approximately $73 million in O&M expenses over the five-year advanced meter deployment period. These costs are part of the overall Energy Cloud project and the Company is seeking recovery of these amounts. To better match recovery of investment and costs, PSE&G seeks approval to defer the project O&M costs as a regulatory asset and recover those costs over a five-year period following the Company's next base rate case. The Company also requests authority to accrue a carrying-cost on the deferred O&M balance, and approval to depreciate AMI meters over 20 years. More detail surrounding these proposals is set forth in Ms. Powell's testimony.

V. SUPPORTING TESTIMONY AND PUBLIC NOTICES

33. Below is a table listing the supporting testimony for this Petition and other attachments:

Appendix Letter or Attachment No.	Document Description
A	Location of MFRs – CEF-EC Program
1	Testimony of Gregory C. Dunlap in support of the CEF-EC Program
2	Testimony of Donna M. Powell describing cost recovery associated with the CEF-EC Program
3	Testimony of Stephen Swetz describing revenue requirement methodologies, cost recovery mechanisms, and bill impact analysis for the CEF-EC Program
4	Typical Residential Customer Bill Impacts – CEF-EC Program
5	Form of Notice of Filing and of Public Hearings – CEF-EC Program

34. The Form of Notice sets forth the requested changes to electric rates and will be placed in newspapers having a circulation within the Company's service territory upon receipt, scheduling, and publication of public hearing dates. Public hearings will be held in each geographic area within the Company's service territory, i.e., Northern, Central, and Southern. The Form of Notice will be served on the County Executives and Clerks of all municipalities within the Company's electric service territories upon receipt, scheduling, and publication of public hearing dates.

35. Notice of this filing and two copies of the Petition will be served upon the Department of Law and Public Safety, 124 Halsey Street, P.O. Box 45029, Newark, New Jersey 07101 and upon the Director, Division of Rate Counsel, 140 East Front Street, 4th Floor, Trenton, New Jersey 08625. The Petition and supporting testimony and attachments will also be e-mailed to the persons identified on the service list provided with this filing.

VI. COMMUNICATIONS

Communications and correspondence related to the Petition should be sent as follows:

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VII. CONCLUSION AND REQUESTS FOR APPROVAL

For all the foregoing reasons, PSE&G respectfully requests that the Board retain jurisdiction of this matter and review and expeditiously issue an order approving the CEF-EC Program, specifically finding that:

1. The CEF-EC Program is in the public interest;

2. The CEF-EC Program, as described herein, is reasonable and prudent;

3. PSE&G is authorized to implement and administer the CEF-EC Program under the

terms set forth in this Petition and accompanying Attachments;

4. The cost recovery proposal and mechanism for the CEF-EC Program set forth in this Petition will provide for implementation of just and reasonable rates, and are approved; and

5. PSE&G may recover all prudently-incurred costs associated with the CEF-EC Program, on a full and timely basis, under the cost recovery mechanism set forth herein.

Respectfully submitted,

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Matthew Weissman

Matthew M. Weissman
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Phone: (973) 430-7052
Fax: (973) 430-5983

DATED: October 11, 2018
Newark, New Jersey

VERIFICATION

STATE OF NEW JERSEY)
:
COUNTY OF ESSEX)

Gregory C. Dunlap, of full age, being duly sworn according to law, on his oath deposes and says:

1. I am Vice President, Customer Operations of Public Service Electric and Gas Company, the petitioner in the foregoing Petition.

2. I have read the annexed Petition, and the matters and things contained therein are true to the best of my knowledge and belief.

3. Copies of the Petition have been provided to the NJBPU, the Department of Law & Public Safety, and the Division of Rate Counsel.

Gregory C. Dunlap

Sworn and subscribed to)
before me this 10th day)
of October, 2018)

Michele D. Falcao

MICHELE D. FALCAO
Notary Public, State of New Jersey
My Commission Expires
November 14, 2021

PUBLIC SERVICE ELECTRIC AND GAS Minimum Filing Requirements: Clean Energy Future - Energy Cloud (CEF-EC) Program	
Minimum Filing Requirement	**Location in Filing**
14:3-2A.2 Project eligibility	
a) Eligible projects within an Infrastructure Investment Program shall be: 1. Related to safety, reliability, and/or resiliency; 2. Non-revenue producing; 3. Specifically identified by the utility within its petition in support of an Infrastructure Investment Program; and 4. Approved by the Board for inclusion in an Infrastructure Investment Program, in response to the utility's petition.	See Attachment 1, Direct Testimony of Greg C. Dunlap
b) Projects within an Infrastructure Investment Program may include: 5. The replacement of gas Utilization Pressure Cast Iron mains with elevated pressure mains and associated services; 6. The replacement of mains and services that are identified as high risk in a gas utility's Distribution Integrity Management Plan; 7. The installation of gas Excess Flow Valves where existing gas service line replacements require them, excluding Excess Flow Valves installed upon customer request pursuant to 49 CFR 192.383; 8. Electric distribution automation investments, including, but not limited to, Supervisory Control and Data Acquisition equipment, cybersecurity investments, relays, reclosers, Voltage and Reactive Power Control, communications networks, and Distribution Management System Integration; 9. The installation of break-predictive water sensors and wastewater sensors to curtail combined sewer overflows; and 10. Other projects deemed appropriate by the Board	See Attachment 1, Direct Testimony of Greg C. Dunlap
c) A utility shall maintain its capital expenditures on projects similar to those proposed within the utility's Infrastructure Investment Program. These capital expenditures shall amount to at least ten (10) percent of any approved Infrastructure Investment Program. These capital expenditures shall be made in the normal course of business and recovered in a base rate proceeding, and shall not be subject to the recovery mechanism set forth in N.J.A.C. 14:3-2A.6.	See Attachment 1, Schedule GD-CEF-EC-4B, of the Direct Testimony of Greg C. Dunlap

14:3-2A.3 Annual baseline spending levels		
a)	A utility seeking to establish an Infrastructure Investment Program shall, within its petition, propose annual baseline spending levels to be maintained by the utility throughout the length of the proposed Infrastructure Investment Program. These expenditures shall be recovered by the utility in the normal course within the utility's next base rate case.	See Attachment 1, Schedule GD-CEF-EC-4B, of the Direct Testimony of Greg C. Dunlap
b)	In proposing annual baseline spending levels, the utility shall provide appropriate data to justify the proposed annual baseline spending levels, which may include historical capital expenditure budgets, projected capital expenditure budgets, depreciation expenses, and/or any other data relevant to the utility's proposed baseline spending level	See Attachment 1,the Direct Testimony of Greg C. Dunlap, and Schedules GD-CEF-EC-4A and 4B
14:3-2A.4 Infrastructure Investment Program length and limitations		
a)	Allowance for Funds Used During Construction (AFUDC) shall be permitted under an Infrastructure Investment Program, but a utility shall not utilize AFUDC once Infrastructure Investment Program facilities are placed in service.	See Attachment 3, Direct Testimony of Stephen Swetz
14:3-2A.5 Infrastructure Investment Program minimum filing and reporting requirements		
1)	Projected annual capital expenditure budgets for a five (5) year period, identified by major categories of expenditures	See Attachment 1, Schedule GD-CEF-EC-4B, of the Direct Testimony of Greg C. Dunlap
2)	Actual annual capital expenditures for the previous five (5) years, identified by major categories of expenditures	See Attachment 1, Schedule GD-CEF-EC-4A, of the Direct Testimony of Greg C. Dunlap
3)	An engineering evaluation and report identifying the specific projects to be included in the proposed Infrastructure Investment Program, with descriptions of project objectives, detailed cost estimates, in-service dates, and any applicable cost-benefit analysis for each project	See Attachment 1, Direct Testimony of Greg C. Dunlap and Schedule GD-CEF-EC-2
4)	An Infrastructure Investment Program budget setting forth annual budget expenditures	See Attachment 1, Schedule GD-CEF-EC-5, of the Direct Testimony of Greg C. Dunlap
5)	A proposal addressing when the utility intends to file its next base rate case, consistent with N.J.A.C. 14:3-2A.6(f)	See Attachment 3, Direct Testimony of Stephen Swetz
6)	Proposed annual baseline spending levels, consistent with N.J.A.C. 14:3-2A.3(a) and (b)	See Attachment 1, Schedule GD-CEF-EC-4B, of the Direct Testimony of Greg C. Dunlap
7)	The maximum dollar amount, in aggregate, the utility seeks to	See Attachment 1,

recover through the Infrastructure Investment Program; and	Schedule GD-CEF-EC-5, of the Direct Testimony of Greg C. Dunlap
8) The estimated rate impact of the proposed Infrastructure Investment Program on customers	See Attachment 4
14:3-2A.6 Infrastructure Investment Program Recovery	
1) Each filing made by a utility seeking accelerated recovery under an Infrastructure Investment Program shall seek recovery, at a minimum, of at least ten (10) percent of overall Infrastructure Investment Program expenditures.	See Attachment 3, the Direct testimony of Stephen Swetz
2) A utility's expenditures made prior to the Board's approval of an Infrastructure Investment Program shall not be eligible for accelerated recovery.	N/A
3) Rates approved by the Board for recovery of expenditures under an Infrastructure Investment Program shall be accelerated, and recovered through a separate clause of the utility's Board-approved tariff.	See Attachment 3, the Direct testimony of Stephen Swetz
4) Rates approved by the Board for recovery of expenditures under an Infrastructure Investment Program shall be provisional, subject to refund and interest. Prudence of Infrastructure Investment Program expenditures shall be determined in the utility's next base rate case.	See Attachment 3, the Direct testimony of Stephen Swetz
5) A utility shall file its next base rate case not later than five (5) years after the Board's approval of the Infrastructure Investment Program, although the Board, in its discretion, may require a utility to file its next base rate case within a shorter period	See Attachment 3, the Direct testimony of Stephen Swetz
6) An earnings test shall be required, where Return on Equity (ROE) shall be determined based on the actual net income of the utility for the most recent twelve (12) month period divided by the average of the beginning and ending common equity balances for the corresponding period.	See Attachment 3, the Direct testimony of Stephen Swetz
For any Infrastructure Investment Program approved by the Board, if the calculated ROE exceeds the allowed ROE from the utility's last base rate case by fifty (50) basis points or more, accelerated recovery shall not be allowed for the applicable filing period.	See Attachment 3, the Direct testimony of Stephen Swetz

ATTACHMENT 1

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF ITS CLEAN ENERGY FUTURE-ENERGY CLOUD PROGRAM ON A REGULATED BASIS

BPU Docket No. __________

PUBLIC SERVICE ELECTRIC AND GAS COMPANY DIRECT TESTIMONY OF GREGORY C. DUNLAP VICE PRESIDENT - CUSTOMER OPERATIONS

October 11, 2018

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
GREGORY C. DUNLAP
VICE PRESIDENT - CUSTOMER OPERATIONS

I. BACKGROUND

Q. Please state your name and professional title.

A. My name is Greg Dunlap and I am the Vice President of Customer Operations at Public Service Electric and Gas Company ("PSE&G" or "the Company"). My professional credentials are set forth in the attached Schedule GD-CEF-EC-1.

Q. What is the purpose of your testimony?

A. I am testifying in support of the Company's proposed Energy Cloud Program (the "CEF-EC" or "Program"), which is part of PSE&G's Clean Energy Future ("CEF") initiative. The CEF-EC will establish a business and technology operating model that enables a number of customer, community, and company smart energy capabilities, or "use cases." At the core of this Program is the deployment of advanced metering infrastructure ("AMI"), comprised of approximately 2.2 million electric "smart" meters, as well as communications and back-office systems. The initial deployment of the CEF-EC ("Release 1") will be an installation of an intelligent energy service platform ("iESP") across the Company's electric service territory, and the initiation of 22 foundational and advanced capabilities or "use cases" that will make use of and maximize the value of the iESP. The purpose of the CEF-EC component of the CEF filing is to obtain approval from the Board of Public Utilities ("BPU" or the "Board") to proceed with the CEF-EC Release 1 plan and business case.

While AMI has been periodically evaluated in the past, the higher costs of smart meters were a hurdle that had to be overcome. No longer. Today, the cost of AMI meters are the same as the meters the Company is currently installing in its electric service territory. AMI not only brings obvious operational savings, but will also provide significant customer benefits. Coincident with the cost of these meters coming into alignment with the cost of current replacement meters, PSE&G's meter replacement activity is on the cusp of a major increase as a number of legacy meters require replacement. Also, with the State's recent focus on pursuing energy use reductions to lower emissions and save customers money, New Jersey can transition from being one of the only states in the nation that has not deployed AMI to one that realizes the benefits of this technology for customers and the environment. The confluence of lower costs, the need to replace a meaningful portion of our customers' meters, an expansion of the potential customer benefits of the program, and State policies make this the optimal time to deploy AMI and begin the journey to realize the broader benefits of the Energy Cloud.

Therefore, PSE&G plans to transition to AMI and to implement the various releases of its Energy Cloud Program. PSE&G is proposing this plan for an accelerated roll-out over the next five years and is seeking BPU approval for certain aspects of this rollout and the resulting realization of customer benefits.

Q. Do you sponsor any schedules as part of your direct testimony?

A. Yes. I sponsor the following schedules that were prepared by me or under my supervision and direction:

- Schedule GD-CEF-EC-1, which describes my professional credentials;

- Schedule GD-CEF-EC-2, which contains the CEF-EC Business Case;
- Schedule GD-CEF-EC-3, which contains the Customer Communication Strategy;
- Schedule GD-CEF-EC-4A and 4B, which contains acutal and projected base capital expenditures and the 10% minimum base spend requirement; and
- Schedule GD-CEF-EC-5, which contains the CEF-EC cash flow that will be recovered through the proposed cost recovery mechanism.

Q. Has PSE&G filed other testimony supporting the CEF-EC?

A. Yes. Donna M. Powell, Assistant Controller for PSE&G, is submitting testimony related to the Company's request to recover the stranded costs associated with the removal of legacy electric meters in favor of smart meters, deferral and recovery of project operations and maintenance expenses, and depreciable lives of the assets being installed. Additionally, Steven Swetz, Senior Director, Rates and Revenue Requirements, is submitting testimony related to the Company's request to recover the capital costs of the program using the Infrastructure Investment Program ("IIP") model.

II. SCOPE OF TESTIMONY

Q. How is your testimony organized?

A. My testimony first provides an overview of the PSE&G Energy Cloud vision, roadmap, and use cases, and then focuses on the initial Release 1 deployment of use case capability and iESP, which will form the foundation to support the CEF-EC.

Q. What are the key elements of your testimony?

A. The following summarizes the key elements of my testimony:

1. A long-term vision for the deployment of an innovative business and technology operating model that will ultimately support a set of 70 use cases across six interrelated domains; three of those domains focus on the utility's customers (*i.e.*, customer, home, and city), and three focus on the utility's assets and operations (*i.e.*, operations, network, and products/services).

2. A long-term CEF-EC roadmap that plans, guides, and prioritizes the validation and deployment of the 70 smart energy capability use cases. Twenty-two initial initiatives, for which the benefits were quantified as part of the business case, comprise Release 1 and will be implemented over the first five years of the PSE&G Energy Cloud deployment, while the remaining 48 initiatives will be implemented over a longer time horizon. These use cases will enable opportunities for enhanced customer engagement and service, new utility products and services, and improved network and operational excellence.

3. The initial program of work, called Release 1, which establishes the foundation for the CEF-EC and has the following scope:

    A. Establishment of the iESP, which is comprised of the core communications infrastructure, smart meters, data, and system services. This will be an extension of PSE&G's current Energy Communications Network ("ECNET") RF Mesh Network across its remaining service territory. Electric smart meter installations will follow the communications network deployment.

B. Deployment of an initial set of 22 foundational and advanced smart use cases covering core processes in customer engagement, new utility products and services, and network operations and planning. These use cases will drive a range of customer and operational benefits totaling $843 million and $887 million, respectively, over a period of nearly 20 years (2019-2037).

C. A viable business case that provides realistic and validated estimates of costs and benefits associated with Release 1. As indicated above, total customer and operational benefits exceed $1.7 billion, compared to total costs to deploy of $794 million. These costs include capital and operational expenditures of approximately $721 million and $73 million, respectively, from 2019 to 2024.

D. A practical and achievable Release 1 plan that includes program management, people and process change, stakeholder communications, and benefits realization streams of work.

The CEF-EC Release 1 includes AMI deployment to electric residential and commercial/ industrial customers only. With approximately 65% of gas meters in PSE&G's service territory already having an Automated Meter Reading ("AMR") device, and the remaining 35% expected to be deployed by year-end 2023, AMR remains at this time a prudent and cost effective strategy for gas meters in PSE&G's service territory.[1] Smart meters for PSE&G's gas customers will be considered again after AMI deployment (for electric meters) and AMR deployment (for gas meters) programs are complete.

[1] AMR permits a Company employee to "read" meters from their automobile or street, as opposed to directly in front of the meter.

Q. How does AMI fit together with PSE&G's Energy Cloud?

A. AMI is the foundational layer of the Energy Cloud. Although the Release 1 implementation is comparable to other AMI deployments across the country in terms of the smart meter and communications technology being deployed, PSE&G intends this technology to be the platform that enables it to:

1. Exceed its core customer service and operating responsibilities;
2. Deploy numerous other smart use case capabilities that are far broader in reach than AMI and the traditional utility model focused on basic customer service, outages and billing. These smart use case capabilities will help PSE&G respond to the changing expectations of customers in regards to service and products;
3. Respond positively and responsibly to the opportunities created by increased solar energy deployment and electric vehicle ("EV") utilization, and potential connectivity to broader smart city networks; and
4. Better serve its customers by becoming a leading smart energy services company.

Q. What are the benefits of the CEF-EC?

A. The CEF-EC and its initial Release 1 deployment of iESP infrastructure and smart capabilities represent critical advances in PSE&G's transformation to a smart energy services utility, and provide significant opportunities and benefits to the following stakeholders:

1. PSE&G customers, by providing them with increased choice and engagement with their energy usage, lower energy bills, improved access to solar installations, reduced outages, innovative rates, new smart products and services, and support for EV infrastructure; and

2. New Jersey's communities and our state as a whole, by promoting energy conservation and efficiency, new utility products and services, and communications network support of smart city programs; improving the environment by reducing harmful emissions; and supporting vulnerable customers such as low-income residents.

The CEF-EC will also strengthen PSE&G itself, through improvements in the Company's operations, asset utilization, customer service, and core business operational excellence.

Q. What is PSE&G requesting in this filing?

A. Given the long-term, transformative nature of the CEF-EC, and the importance of Release 1 to fully achieving its objectives and attaining its benefits, PSE&G is asking the Board to approve the following:

1. Release 1 plan and deployment costs: PSE&G seeks Board approval to recover the capital costs to deploy iESP via the IIP mechanism set forth in BPU regulations. The testimony of Mr. Swetz provides the details of this cost recovery request.
2. Specific treatment of stranded asset costs: deploying 2.2 million electric meters over a five-year period will require removal of a significant number of legacy meters prior to those meters being fully depreciated. As set forth in more detail in Ms. Powell's testimony, PSE&G seeks BPU approval to defer the undepreciated cost as a regulatory asset and recover it over a fixed five-year period following the Company's next base rate case. PSE&G will test all meters removed from service in accordance

with the New Jersey Administrative Code,[2] with the cost of this testing included in O&M spending.

3. Specific treatment of project operational costs: deployment of iESP will require approximately $73 million in O&M expenses over the five-year meter deployment period. As also discussed in Ms. Powell's testimony, PSE&G requests authority to defer the project O&M cost to a regulatory asset and recover it over a five-year period commencing after the Company's next rate case. PSE&G also requests authority to record a carrying-charge on the unrecovered balance of this regulatory asset.
4. Approval to depreciate AMI meters over 20 years: As set forth in more detail in Ms. Powell's testimony, this will match the depreciable life to the meter's expected useful life.
5. Approval of Opt-Out Provisions: PSE&G proposes that residential electric customers be able to opt-out of receiving a smart meter. Customers that opt-out will require a manual read of their meter. PSE&G proposes that residential customers wishing to opt-out of a smart meter be subject to a monthly charge of $20.00 per account for manual meter reading. This fee is consistent with the monthly cost per customer to manually read the meter, and is comparable with other utility benchmarking of opt-out programs and costs. Additionally, customers choosing to opt out after the smart meter is installed on their premises will be charged a one time fee of $45 to change to a solid state, digital, non-radio frequency emitting meter This applies to residential

[2] *See* N.J.A.C. 14:3-4.7(c)(6).

customers only. The opt-out capability will not be available to commercial and industrial customers.

Q. Does the CEF-EC relate to other PSE&G filings before the Board?

A. Yes. The other components of PSE&G's Clean Energy Future initiative, as well as the Energy Strong II filing (BPU Docket Nos. EO18060629 and GO18060630) have a strong nexus to the CEF-EC. The use case capabilities of the iESP can provide additional data, network, and process support for the energy efficiency, electric vehicle, and storm hardening initiatives proposed in those filings. For example, more detailed load, voltage and outage data can play an important role in the analysis, planning, and deployment of energy conservation and quality programs, as well as optimizing the planning of a network and asset hardening initiative. The CEF-EC is designed to manage the alignment of objectives and deployment dependencies across these initiatives.

Q. Does this CEF-EC filing fulfill the requirement in Recommendation #12 (RQ-BPU-2) of the BPU "Staff Report and Recommendations on Utility Response and Restoration to Power Outages During the Winter Storms of March 2018" ("BPU 2018 Storm Report")?

A. Yes. Recommendation 12 states that the New Jersey electric distribution companies other than Rockland Electric Company "shall each submit a plan and cost benefit analysis for the implementation of Advanced Metering Infrastructure (AMI). The EDCs' plans should focus on the use and benefits of AMI for the purpose of reducing customer outages and outage durations during a major storm event."

The CEF-EC Business Case submitted with this filing identifies the customer and operational benefits associated with the CEF-EC Release 1, which include the restoration benefits associated with smart meters (*i.e.*, reducing customer outages and outage durations during a major outage event). These benefits are also discussed below.

Q. How will smart meters be used to reduce the number and duration of outages during major outage events?

A. The CEF-EC smart meter deployment will provide PSE&G with much greater visibility of its electric distribution system. District operators will have the ability to "see" the operational status of the network down to the customer meter level, which gives a much fuller picture of how the distribution system is performing than does the existing system, which generally provides circuit-level information. This increased level of operational visibility and situational awareness will allow PSE&G to make more informed decisions, which will lead to better resiliency and customer service. Restoration improvements from the deployment of smart meters will likely come from the faster identification of "nested outages" (*i.e.*, secondary and service outages that are not identified or fixed during initial restoration activities, which are focused on primary distribution circuits). This enhanced identification capability can shorten the overall system minutes of interruptions (and the associated System Average Interruption Duration Index or "SAIDI"), as well as shorten the tail end of major storm event restoration activities.

There are instances during outage restoration activities where there is significant damage on secondary services that do not become apparent until after the primary distribution circuit is restored. In these cases, the "nested" outages on the secondary side will not be identified until well after the restoration crews have departed and moved on to the next restoration area. Without smart meters, the method to locate these "nested" outages is to depend on further customer restoration calls, which adds significant delays in completing the restoration of the affected area as well as customer frustration. For example, it took PSE&G an extra one to two days to address approximately 16,000 service and secondary outages during the October 2011 snowstorm following Superstorm Sandy. If smart meters had been in place at that time, with their ability to ping devices and directly verify that an area has been restored, those restoration delays would not have occurred.

The increased visibility down to the meter level will allow PSE&G operators to determine exactly which premises are still without power. By using other network and neighborhood information, PSE&G will be able to determine what restoration activities should be performed in an area before troubleshooters and crews move to the next area. This faster identification of "nested" outages can significantly shorten restoration activities, and eliminate restoration crews visiting the same area multiple times. This improved system awareness of outage location allows for more efficient restoration activities which, in turn, will shorten the "tail" of major event responses. This decreases the system outage durations for customers, allows PSE&G to go back to "normal" operations mode faster, and potentially allows for the release of mutual assistance crews earlier. Up to a 2% improvement of system SAIDI can be achieved with the elimination of these nested outages.

Q. What are the estimated benefits associated with using smart meters to identify and restore customer outages during major events?

A. PSE&G has estimated the benefits associated with smart meters to be $44 million through 2037. [3] These benefits are realized by (1) shortening the duration of major outages and, therefore, not having to expend resources during the tail of a long duration outage; and (2) reducing truck rolls and inbound outage calls that, in the absence of smart meters, would have to occur as part of outage callbacks as nested outages are identified.

Q. Are there additional potential benefits that were not calculated as part of the CEF-EC Business Case?

A. Yes. The value that customers place on lost load was not calculated as part of the CEF-EC Business Case. The United States Department of Energy ("DOE")[4] has a model to calculate the value of lost load during an outage, which is the value that customers place on having service.

Q. Will the CEF-EC improve PSE&G's ability to provide more accurate and timely Estimated Time of Restoration ("ETR") communications?

A. Yes. Recommendation #15 (RQ-PSE&G-1) in the BPU 2018 Storm Report calls for PSE&G to provide a global ETR separately for each of its four operation divisions within 24 hours after a weather event or other major event has exited the service territory. Part of the ETR use case included in the CEF-EC Release 1 deployment (*i.e.*, Use Case #17) incorporates analytics and automation to improve the calculation and communication of ETR.

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[3] This figure excludes the benefits arising following an event on the order of Super Storm Sandy, and therefore should be considered a conservative estimate of the benefits of this program.

[4] https://icecalculator.com/home

III. THE ENERGY CLOUD

Q. What is the long-term benefit of the PSE&G Energy Cloud?

A. The CEF-EC will lead New Jersey into a smart energy future by enabling PSE&G to become a key provider and enabler of smart digital capabilities. Driven by the need to respond to increased customer and community expectations (including expectations related to worsening weather patterns and storms in the northeastern part of the country), and also driven by the need to manage future operational complexity caused by the increase in, *e.g.*, distributed generation, utilities will need to respond and deploy a range of digital smart capabilities. In terms of choice, customer's options will broaden to include, for example, non-industry products and services (*e.g.*, Alexa, cable TV, internet), and the bundling of utility and non-utility products and services (*e.g.*, home security, home energy management). Further, this increased operational complexity and new digital capabilities will provide opportunities to increase the knowledge and skills of PSE&G personnel, which in turn will improve customer and network operations performance.

Given this context, New Jersey requires a deliberate long-term strategy and plan to deploy smart digital capabilities. This should include the implementation of smart technologies such as smart meters, two-way communication networks, and the type of advanced capabilities described in my testimony. As set forth below, the CEF-EC will provide a stable and secure platform environment that enables the six key smart capabilities listed above, *i.e.*, smart customer, smart home, smart city, smart operations, smart network, and smart products and services.

Q. What is required in order to achieve the CEF-EC benefits and follow the proposed roadmap?

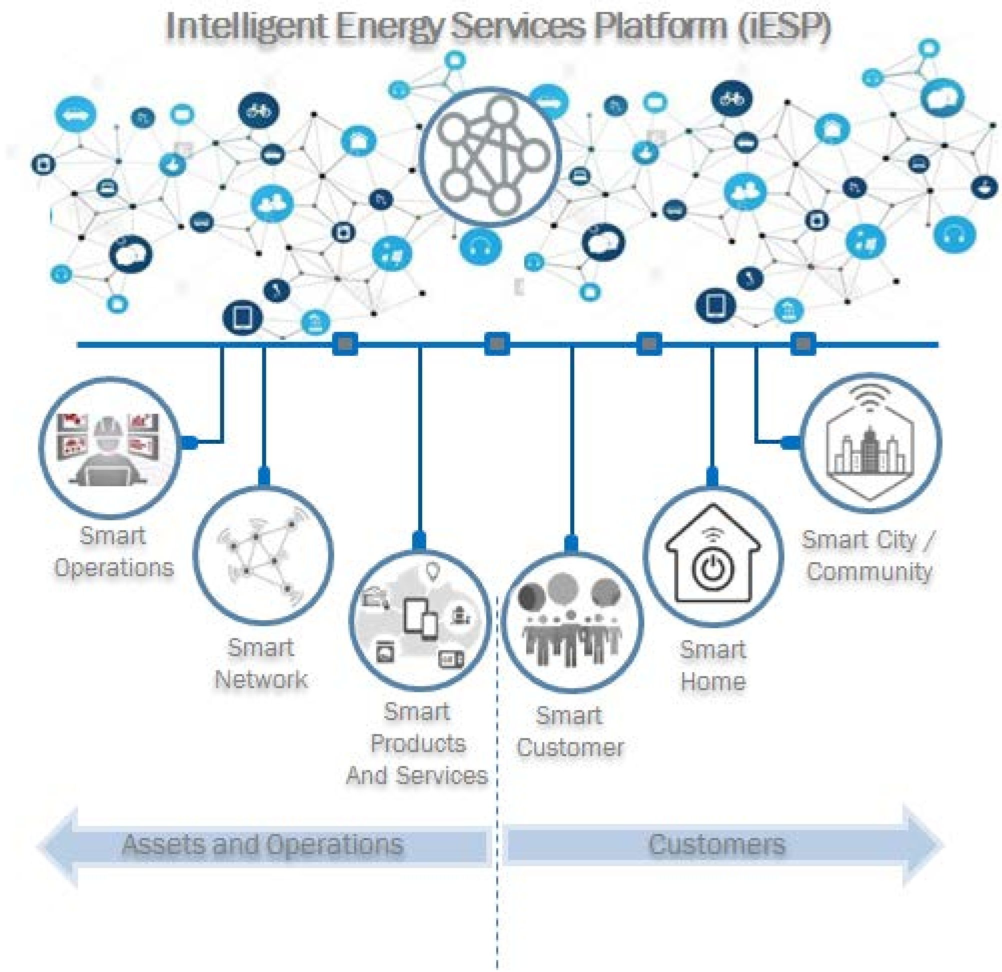
A. To achieve the CEF-EC benefits, PSE&G requests that the Board approve the following two core components:

1 A foundational iESP made up of smart meters, a communications network, and back end data management processes and systems that provide scalable, secure, safe, reliable bi-directional data and communication network services; and

2 A broad range of iESP-enabled CEF-EC smart utility and customer-related capabilities ("use cases") spread across the six interrelated asset and customer focused smart energy domains identified above and described in more detail below. The EC Business Case (Schedule GD-CEF-EC-2) defines the people, process, and technology applications required to deploy each use case and realize the associated customer and operational benefits.

Figure 1 below illustrates this overall CEF-EC architecture in terms of its six core smart energy domains and its core enabling iESP technology. It also shows the two main focus areas of the six smart domains: Customers, and Asset and Operations.

Figure 1 – The PSE&G Energy Cloud Architecture



Q. What are the six CEF-EC smart domains and what will they enable?

A. The CEF-EC is intended to cover six interrelated smart capability domains, each of which will provide benefits to customers, New Jersey, or the Company when deployed. An overview of each and the potential value they bring follows:

- Smart Operations - support a reliable and customer-centric utility where automated operations and processes, tailored and predictive customer experience, and service flexibility are the norm. The proposed development will increase customer service and efficiency, and improve operational performance through a number of smart capabilities that leverage smart meter data and new technologies like process automation, robotics and artificial intelligence, to enable enhanced understanding of real time operational status and performance. Customer experience and knowledge will be greatly enhanced using more granular customer data used by customer operations like daily usage, voltage profiles, and smart appliance information, and by increasing bill accuracy, customers' ability to understand their energy consumption, and enhanced self-service.

- Smart Network - The historically predictable, linear electric distribution model is evolving into a distributed network of variable sources of energy and demand points. The evolution is driven by distributed energy resources ("DERs") reaching critical mass, main stream electrification of transportation, and prevalence of microgrids and storage resources across the service area and to all customer types. The CEF-EC will enable better reliability, safety and increased customer service for PSE&G customers through deploying distributed intelligence sensors, controllers, and communications to "see" and "control" the real time operational and safety status and performance of PSE&G's network.
- Smart Products and Services - Many utilities and non-utilities are leveraging smart infrastructure, sensors, and data to develop new digital products and service offerings, often with business partners, and particularly in the context of the smart customer and home. The CEF-EC makes integration of smart products and services possible. Examples include in-home networks ("IHN"); appliance monitoring and service; safety and security; and DER facilitation, where PSE&G could assist customers with sizing and

locations of solar or EV charging. The CEF-EC can also support a range of "as a Service" or "aaS" subscription based product offerings that could include:

- o <u>iESP Network Communications (NaaS)</u> - making spare capacity on the iESP communication network available to customers or third parties; for example, providing access to the iESP network for a water utility to collect its smart meter data;
- o <u>iESP Data as a Service (DaaS)</u> - providing expanded iESP data to customers and authorized third parties; for example, collecting data for a water company from its smart meters connected to the iESP network and providing that data to the water utility for billing; and
- o <u>Utility as a Service (UaaS)</u> – provision of PSE&G back office functions (*i.e.*, metering, billing, collections) to support water companies or small municipalities. This could include, for example, collecting data for a water utility from their smart meters connected to the iESP network and performing billing and other related back-office functions on its behalf.

- <u>Smart Customers</u> - In today's digital world, the interaction between utility companies and customers is increasingly influenced by companies in other sectors, not simply other utilities. Companies that currently provide an effortless customer experience (service and mobile applications), such as Amazon and Netflix, have become integral to many customers' daily activities and the benchmark for convenience and service. This means that customers will welcome, and ultimately require, higher levels of engagement with their utility and energy usage through capabilities that the CEF-EC enables. These include full visibility of customers' energy usage, tools to help them with efficiency, bill alerts, services delivered by home assistants, solar and EV support, and choice of a range of tailored rate options.

- Smart Home - The Smart Energy Home includes all smart appliances (*i.e.*, washers, dryers, refrigerators), smart home safety and security systems (*i.e.*, sensors, monitors, cameras, and alarm systems), and smart home energy equipment (*i.e.*, smart thermostats and smart lighting). The CEF-EC makes smart homes possible by providing convenience and sustainability, as connected devices can optimize lighting, temperature, EV charging, and other end uses of electricity.
- Smart City – A Smart City is an urban area that harnesses digital technology to create a sustainable and intelligent infrastructure. In a Smart City, various smart devices connected to the network (*i.e.*, the Internet of Things) can manage energy use, control lighting, manage traffic, analyze air quality, communicate with citizens, and otherwise optimize the efficiency of city operations. Through the CEF-EC, PSE&G would play a supporting role by providing network and data services to support these types of Smart City initiatives.

Q. What are the smart capabilities ("use cases") and what will they enable?

A. The smart use cases developed through this Program are unique combinations of people, process, technology, and data capabilities that, when deployed, will enable PSE&G to improve operational performance and customer satisfaction. These use cases were chosen from industry and non-industry sources for their alignment with the overall vision and objectives of the CEF-EC. Figure 2 below lists the 70 use cases that will be deployed in the program. Twenty-two initial use cases, for which the benefits were quantified as part of the business case, will be deployed in release one and will be implemented over the first five years of the PSE&G Energy Cloud deployment, while the remaining 48 use cases will be implemented over a longer time horizon in three subsequent program releases according to the Program roadmap.

Figure 2 – The PSE&G Energy Cloud – Smart Capabilities ("use cases")

PSE&G Applicable Use Case Capabilities (70) – On the Roadmap

Release 1 – with iESP (22)

1. Enhanced Customer Engagement & Communications
2. Rate Analyzer & Comparator
3. Usage & Bill Alerts, Saving Tips
4. Interactive Energy Demand & Bill Management
5. Customer Segmentation & Behavioural Analysis
6. Customer Power Quality
7. Customer Energy Efficiency (Smart Thermostats)
8. Customer Service & Call Center Performance
9. Customer DER/PV/EV
10. Customer Device Safety
11. iESP Sensor, Network & Data Operations
12. Remote Move in / Move Out
13. Remote Disconnect / Reconnect
14. Next Generation Meter to Cash
15. Network Connectivity Analysis
16. Outage Detection & Restoration
17. Outage Response Notification (ETR)
18. Voltage Monitoring & Analysis (PQ)
19. Asset Load/Phase Management, Balancing & Power Analysis
20. Load Profiling & Forecasting
21. Distribution Losses
22. Revenue Protection & Assurance

Release 2 (15)

1. Customer Demand Response
2. Asset Management & Health
3. Reliability Analysis, Optimization, & Cost/Benefit
4. Distributed Generation Analysis
5. System Planning & Investment Portfolio
6. Distribution Automation & SCADA
7. Street-Lighting Remote
8. Customer Pre-Pay
9. Innovative Rate Development
10. Customer Smart Home/Appliances/Devices
11. Network as a Service
12. Data as a Service
13. Critical Peak Pricing
14. Demand Response Control
15. Conservation Voltage Reduction & Volt / Var Optimization

Release 3 (16)

1. Smart City
2. Microgrids
3. Innovative/New Products & Services
4. Customer Gamification & Loyalty Programs
5. Distribution/Bi-Directional Marketplaces
6. Asset Performance, Maintenance & Visualization
7. Load Curtailment / Limiting
8. Advanced Auto Detection & Location
9. Automated Fault Isolation & Restoration (FLISR) – Self Healing
10. Volt / VAR Control
11. Customer Safety (Gas Leak, Co2)
12. Permanent Power Quality Management
13. Utility, Customer, & Community Energy Storage
14. Asset Risk Analysis and Risk Scoring
15. Optimal Switch / Recloser Placement
16. Dynamic Circuit Reconfiguration

Release 4 (17)

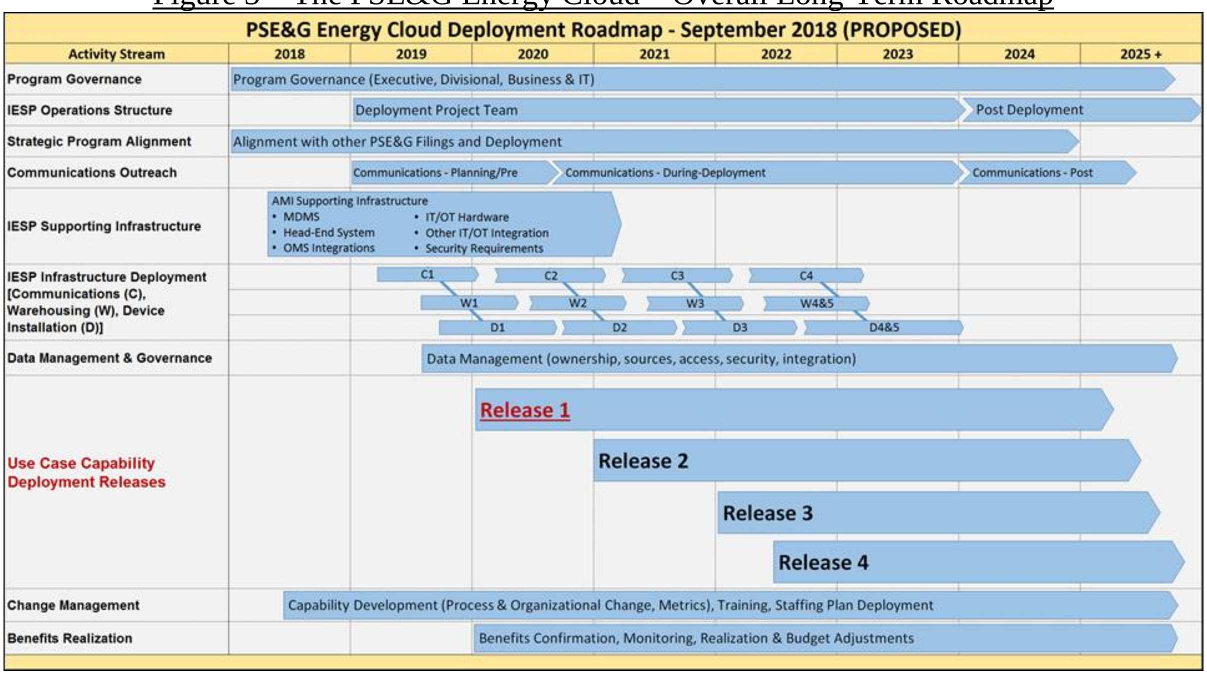
1. Load Control, Adjustment, Optimization, & Contingency
2. Customer Building Automation Optimization
3. Real-Time-Pricing
4. Storm/Lightning Analysis
5. Vegetation Management
6. Environmental / Sensitive Area Analysis
7. Storm Prediction
8. Advanced DER Planning & Management (DERMs)
9. Control of DERs and HVAC Equipment
10. DER Operations & Control
11. Battery Aggregation & Control
12. PV/DER Output Forecasting
13. Real-Reactive Load-Voltage Management
14. Optimal Capacitor Bank Design & Placement
15. Switching Schedule & Safety Management
16. Ancillary Services
17. Energy Management & Frequency Control

Q. Please outline the long-term deployment roadmap for the establishment of the PSE&G Energy Cloud?

A. Based on the identification, analysis and prioritization of the smart capabilities of the CEF-EC, the following roadmap was developed. This deployment roadmap is structured around the 70 applicable use cases organized into four capability release groups based on value, complexity, and type (*i.e.*, foundational, advanced or future), and aligned with the planned deployment of smart meters, back-end systems, and communications infrastructure. Figure 3 below details the overall CEF-EC Deployment Roadmap.

Twenty-two of the 70 use cases have been chosen for the initial implementation ("Release 1"). The remaining use case capabilities are planned for subsequent releases according to the roadmap. These remaining use cases will require further detailed evaluation, justification, and planning before they are scheduled for implementation, and are not the subject of PSE&G's request in this filing.

Figure 3 – The PSE&G Energy Cloud – Overall Long-Term Roadmap



IV. ENERGY CLOUD RELEASE 1 DEPLOYMENT

Q. Please describe the initial CEF-EC Release 1 scope.

A. As discussed above, the Release 1 deployment of the iESP technology infrastructure and the 22 use case capabilities will establish the foundation of PSE&G's smart energy vision and roadmap. The following section lays out the key components of the Release 1 program plan and scope:

- Establishment of the iESP, which includes the deployment of smart data and technology infrastructure -- systems, communications, meters and sensors -- that enables the smart use case capabilities. The Release 1 iESP implementation will include the extension of the current ECNet RF Mesh Network, currently deployed for commercial and industrial customers, across the remaining PSE&G service territory including:
  - 182 additional data collectors/gateways (currently 26 deployed);
  - 2,370 additional routers/bridges (currently 2,300 deployed);
  - 2.2 million smart electric meters (currently 15,000 deployed for commercial and industrial customers);
- The deployment of smart electric meters, which will take place over approximately five years. The deployment will ramp up over time, with AMI meters being installed to replace aged and/or inaccesible non-AMI meters over the first three years. In year three, PSE&G will accelerate targeted deployment of AMI, focusing on installing in locations that traditionally have access issues. Full deployment of approximately 1 million meters a year will take place in years 4 and 5.
- The deployment of the initial 22 smart energy use case capabilities (listed above and described later in this section) that will enable a range of foundational and advanced smart capabilities across the six smart domains. The costs and benefits for these 22 initial use cases are accounted for in the Business Case Overview presented in Figure 5 below.

Q. Please describe the proposed CEF-EC Release 1 Program Deployment Plan.

A. As the initial step in the CEF-EC, PSE&G is proposing to deploy Release 1 -- the iESP infrastructure, system and data services, the 22 business and technology use case capabilities, and the relevant governance, project management office ("PMO"), change, communications, and technology infrastructure work streams.

Q. Please describe the 22 use cases that comprise Release 1 of the CEF-EC and their benefits.

A. The 22 smart capabilities (use cases) will, alongside the iESP infrastructure, system, and data services deployment, enable a number of smart capabilities that in turn will deliver a number of customer and operational benefits. With respect to customer benefits, use case capabilities planned in Release 1 will focus on enhanced engagement and service, automated alerts and tips, support for energy efficiency and DER needs, and a range of advanced self-service energy and billing capabilities. Other customer-focused capabilities include the availability of additional usage and service data that will enable customers to reduce their bills by matching their profile to a better rate or joining energy efficiency initiatives. Meter alerts can warn customers and PSE&G if there are issues, particularly safety related, with their connections. For example, it was reported in early September 2018 that a smart meter Con Edison installed in a New York residence alerted the utility to an unsafe condition behind the meter, possibly preventing a house fire.[5] The ability to communicate in real time with the meter will also deliver a number of outage and power quality benefits. These capabilities and additional data should result in increased customer service and satisfaction.

[5] https://newyork.cbslocal.com/2018/09/06/con-edison-smart-meter-new-rochelle/.

With respect to operational benefits, Release 1 capabilities will focus on leveraging additional and more accurate data and infrastructure to enable new capabilities, including automated and on-demand meter reading, remote disconnect and reconnect services, automated move-in and move-out work, active voltage and load management, outage detection and response, and energy theft protection. These capabilities are expected to deliver significant operational benefits for meter reading, avoided work (truck rolls and service appointments), improved outage response, reduced bad debt and write-offs, improved meter to cash efficiencies, and reduced energy theft.

The proposed 22 CEF-EC Release 1 smart capabilities (use cases) are listed in the table below (Figure 4), which describes in more detail the use cases in terms of the types of enabled capabilities and expected value for customers and stakeholders.

Figure 4 – Release 1 Use Cases

Use Case #	Use Case Name	Use Case Overview & Value
1,2,3,4	1. Enhanced Customer Engagement & Communications	A set of customer benefiting functions and analytic applications that provide visualizations and analytics across a variety of customer and iESP data combined with other data – bills, usage, prices, tips, alerts, energy efficiency, appliance profiles, new products and services, notifications, and available through mobile and web portals.
	2. Rate Analyzer & Comparator	
	3. Usage & Bill Alerts, Saving Tips, Interactive Bill Presentment	
	4. Interactive Energy Demand & Bill Management (Portal part of Meter Data Management System - MDMS project)	
5	Customer Segmentation & Behavioral Analysis	Provides the ability to develop highly targeted customer segmentation models based on more granular energy usage data and customer interactions to improve customer service, marketing, time of use ("TOU") rates, new products and services, and planning load forecasts.

Use Case #	Use Case Name	Use Case Overview & Value
6	Customer Power Quality	Capability that allows PSE&G to obtain voltage, load, and alert data directly from the meter to analyze customer power quality issues (flicker, sag, swell), without the need for further instrumentation, and can also help ensure appropriate corrective actions are taken (utility or customer side of the meter).
7	Customer Energy Efficiency Programs (Thermostats & Supporting CEF-EE Filing)	iESP data gives the customer the ability to make more educated energy efficiency related decisions, change energy consumption habits, and ultimately lower utility bills. This is enabled by providing customers with detailed iESP data through web or mobile portals, smart devices and in-home devices. PSE&G can also use this iESP data to design and offer energy efficiency products and services.
8	Customer Service & Call Center Performance	Enables the use of broader range of information (including iESP) to increase call center knowledge, improve service, improve customer satisfaction, and lower customer costs by bringing together historical and real-time information to support decision analysis and improve the customer experience.
9	Customer DER/PV/EV	Services and systems that will use iESP data to help assist customers with DER (solar, EV, energy storage) installations and the management of any power quality issues that occur as a result of variable DER load
10	Customer Device Safety	Enhances customer safety by using iESP data, such as alerts and voltage data to detect safety issues relating to customer meters and power connections such as hot sockets and fallen wires, and provide alerts to customers and PSE&G.
11	iESP Sensor, Network & Data Operations	Back office processes and systems that manage the initial iESP infrastructure deployment and the ongoing and updated Meter Operations business function including acquisition, warehousing, testing, installation, maintenance, data streams and quality, alarm management, and meter data management.
12	Automated Move in/Move out & Remote Disconnect/ Reconnect (Primarily in MDMS project)	This use case addresses the messages exchanged between Customer Operations processes and Smart Meter through the HeadEnd and Network when a customer move in or out request is issued by Customer Operations or other cudstomer processes. PSE&G currently sends a metering service employee to move a customer in or out for a variety of reasons. With iESP, the turn on functions and on demand read functions to support these processes can be automated and performed remotely and instantaneously, thereby increasing customer satisfaction and efficiency across various customer processes. • Electric operations reduction due to MIMO and Collection activity automated. • Gas operations reduction due to remote MIMO and Collection activity automated: • Cost reduction due to 85k avoided truck roll costs for move in move outs
13	Remote Disconnect/ Reconnect (Primarily in MDMS project)	This use case addresses the messages exchanged between Customer Operations processes and Smart Meter through the HeadEnd and Network when a meter connect/disconnect request is issued by Customer Operations or other processes. PSE&G currently sends a metering service or collections employee to connect or disconnect the meter for a variety of reasons. With iESP, the

Use Case #	Use Case Name	Use Case Overview & Value
		reconnect/disconnect functions to support these processes can be automated and performed remotely and instantaneously, thereby increasing customer satisfaction and efficiency across various customer processes. • Electric operations reduction due to remote turn-on/off of electric meters • Gas operations reduction due to remote turn-on/off of gas meters: • Cost reduction due to 171k avoided truck roll costs for move in standard turn on/turn offs • Cost reduction due to avoided truck roll costs for turn on/turn off type events • Reduction in writes offs due to energy consumed on inactive accounts. Being able to remotely detect and disconnect will reduce the occurrence. $20m written off yearly. Assuming 70% reduction due to iESP capabilities
14	Next Generation Meter-to-Cash	With more granular and quality iESP data available, alongside numerous other internal data sources, PSE&G can optimize and re-invent their meter-to-cash processes and drive out inefficiencies, increase service, and reduce costs. The iESP data is significantly more accurate at the source and by mapping the data from the iESP to its end use, leakage can be detected more easily. The cost of these losses is spread across the customer base so any improvement ultimately reduces customer bills. • Billing cost reduction due to a decline of billing irregularities and analysis work • Collection cost reduction due to a decline of backoffice collection workload • Reduction in bad debt due to improvement in field collections. Being able to remotely detect and disconnect will reduce the occurrence. $60m written off yearly. Assuming 31% reduction due to iESP capabilities
15	Network Connectivity Analysis	PSE&G's electricity network is complex, covers a large area, and provides power to different customers at different voltage levels. Ensuring that the required sources and end-use loads are correctly represented in operations systems is often very difficult. The iESP end-point meters can extend the network model and enable a high level of accuracy of connections and phasing, which in turn results in better planning and operations performance, and enables many other network dependent use cases.
16	Outage Detection & Analysis	Uses outage data from operations systems and smart meters to identify and verify possible outage locations, as well as identify network sections and specific customers (and numbers) that are out of power. This data is provided and displayed in real-time, to allow analysis, fast response, and crew dispatch to the precise location (down to meter) with information on the potential cause of the outage in order to more quickly restore power and ensure all customers are restored.

ATTACHMENT 1

Use Case #	Use Case Name	Use Case Overview & Value
17	Outage Response Notification (ETR)	Use iESP outage data to calculate and communicate reasonable, more accurate, and acceptable outage status and restoration times to customers in real time. This largely eliminates one of the most common customer complaints about utility service, *i.e.*, inaccurate estimated restoration times. Messaging solutions within scope of this use case include Interactive Voice Response (IVR), web portals, text messaging, social media, mobile applications, and press releases.
18	Voltage Monitoring & Analysis	Using iESP data and other network data sources, voltage readings are captured, visualized, and system-wide analysis is run to determine locations where voltage violations exist both above and below nominal voltage. Utilities can utilize this information for accurate analysis of voltage issues and a base for voltage planning and optimization across the network. Further, this information can help planners identify strategic locations for deployment of Volt/VAR optimization equipment.
19	Asset Load/Phase Management, Balancing & Power Analysis (incl. Transformer Load Monitoring & Customer Load Curtailment/Limiting)	Using iESP data and other network data sources, load data is imported, aggregated, and visualized. Power flow analysis is run to examine and monitor loading profiles of every network asset along the feeder from the substation to the smart meter. This use case gives visibility of loading profiles and load flows of all network assets and customers with real-time or overnight iESP data updates. This information can be used by planners and operators to determine areas of overloading of assets on the system, plan responses to major events, execute asset balancing, and customer load curtailment.
20	Load Profiling & Forecasting	Capability that would enhance load profiles and forecasts by using iESP data in combination with network, customer billing or other data (*e.g.*, weather) to perform more detailed usage analysis. This is beneficial to customers and PSE&G planners by supporting optimized planning of load growth, which in turn leads to optimized capital spending and reliability of the network.
21	Distribution Losses	Distribution losses can be identified by comparing the iESP end-point meter usage data with usage data at the distribution entry point (*i.e.*, substation). Areas of high losses or network sections with particularly high losses can be identified through the analysis. Further analysis on the causes of the high losses will shed light into the different types of corrective / mitigating actions that can be taken to reduce the technical losses. Technical losses are spread across the customer base, so any improvement in this area could reduce customer bills.
22	Revenue Protection & Assurance	Revenue protection refers to the prevention, detection, and recovery of losses caused by interference with or theft of utility service. This use case will leverage smart meter consumption, as well as voltage and event data, to detect energy theft and meter tampering by employing multiple screening techniques, including cross-service correlations. Energy theft is spread across the customer base, so any improvement reduces customer bills.

Q. Please describe the governance and organization structure planned for the implementation of Release 1.

A. A project team will be established to implement Release 1. PSE&G in forming this team will consider all aspects of the activity, experience, and skills required to ensure the team has the proper governance, organization, and capacity to successfully undertake and complete this work.

V. ENERGY CLOUD RELEASE 1 COSTS AND BENEFITS

Q. Please provide an overview of the proposed CEF-EC Release 1 costs and benefits.

A. The conclusions included in the CEF-EC Business Case, which is provided as Schedule GD-CEF-EC-2, represent the culmination of a rigorous process undertaken in collaboration with PA Consulting Group to identify and quantify potential smart energy benefits (*e.g.*, cost savings, reliability performance improvement, staffing issues) as they relate to the scope of Release 1 of the Program. Societal and customer benefits that cannot easily be quantified are discussed qualitatively in the CEF-EC Business Case, and are not discussed in my testimony.

Q. Is the CEF-EC Release 1 program cost effective?

A. Yes. To summarize the quantifiable benefits and costs of Release 1, it is estimated that during the deployment and realization period of nearly 20 years (2019-2037), the CEF-EC Release 1 will deliver:

- $1.7 billion of quantatitive benefits versus $794 million of costs;
- Up to an estimated 2% improvement in reliability metrics, specifically SAIDI; and

- A potential 2,761 tonnage reduction in carbon emissions due to fewer truck rolls, plus potential environmental benefits of lower customer usage.

The costs and benefits are detailed in Schedule GD-CEF-EC-2 CEF-EC Business Case (Section 5.2). The following table (Figure 5) summarizes the key cost and benefits for the CEF-EC Release 1 deployment:

Figure 5– Business Case Overview

Business Case Overview $M		
Benefits	**Nominal Value**	**Present Value***
1. Operational Benefits	$887	$384
2. Customer Benefits	$843	$372
3. Total Benefits (1 + 2)	**$1,730**	**$756**
Costs		
4. O&M Costs	($73)	($56)
5. Capital Costs	($721)	($553)
6. Total Costs (4 + 5)	**($794)**	**($609)**
Net Benefits		
7. Net Benefit (3 – 6)	**$937**	**$147**

Benefits Overview $M		
Operational Benefits	**Nominal Value**	**Present Value***
Customer Operations	$567	$245
Grid Operations - Gas	$196	$85
Grid Operations – Electric	$124	$54
Total Operational Benefits	**$887**	**$384**
Customer Benefits		
Time of use rates	$38	$16
Better storm outage response	$38	$17
Reduction in usage related to inactive accounts	$266	$118
Reduction in write-offs	$353	$153
Avoided energy theft	$138	$62
Recovered line loss due to slow meters	$11	$5
Future Capabilities	Individual Cases	
Total Customer Benefits	**$843**	**$372**
Total Benefits	**$1,730**	**$756**

As can be seen above, the net effect of the benefits and costs coming from CEF-EC Release 1 is a case that is economically viable. Benefits exceed costs by $937 million on a nominal basis and by $147 million on a present value basis.

Q. Please explain the primary sources of customer benefits.

A. The CEF-EC provides for significant customer benefits. These benefits begin in year four of the deployment and increase over time, reaching steady-state approximately two to five years after deployment is completed, depending on the use case. The details of the benefits calculation are included in the GD-CEF-EC-2 CEF-EC Business Case (Section 5.2). The estimated total reductions in customer bills from 2019 through 2037 via the CEF-EC will be realized through various methods as outlined below:

1) Time of Use Rates: iESP will provide data to customers to better manage energy use. Given this information, we expect customers to move to our existing time of use

RLM rate that will shift usage to off-peak hours, saving on energy charges totaling approximately $38 million.

2) Better storm outage response: iESP increases outage response and reduces duration of outages by allowing PSE&G operations to contact and check the status of individual smart meters. This capability will reduce the impact of nested or isolated outages, particularly at the backend of a major storm event, resulting in around $38 million in savings, which will be realized in PSE&G's base rate cases.

3) Reduction in usage related to inactive accounts: using the remote data access and reconnect/disconnect functionality of the smart meters, PSE&G can significantly improve the detection and elimination of usage on inactive accounts. These costs are spread across the customer base; thus, this improvement reduces customer bills, totaling approximately $266 million. Electric savings will be realized annually through the Societal Benefits Charge ("SBC") filing; gas savings will be realized in PSE&G's base rate cases.

4) Reduction in write-offs: using the remote data access and reconnect/disconnect functionality of smart meters, PSE&G can significantly improve the detection and elimination of non-collectable accounts and subsequent write-offs. These costs are spread across the customer base; thus, this improvement reduces customer bills, totaling approximately $353 million. Electric savings will be realized annually through the SBC filing; gas savings will be realized in PSE&G's base rate cases.

5) Avoided energy theft: using the remote data access and alert functionality of smart meters, PSE&G can improve the detection and recovery of energy theft. These costs

are spread across the customer base; thus, this improvement reduces customer bills, totaling approximately $138 million. The savings will be realized in PSE&G base rate cases through lower line loss percentages in customer rates.

6) Recovered line loss due to slow meters: given the high data accuracy and currency of smart meters, PSE&G can virtually eliminate the incident of slow meters. These costs are spread across the customer base; thus, this improvement reduces customer bills, totaling approximately $11 million. The savings will be realized in PSE&G base rate cases through lower line loss percentages in customer rates.

Q. Please describe the sources of the operational benefits.

A. The CEF-EC also provides for significant operational benefits due to cost reductions in three areas, as described below. These benefits begin in year four of the deployment and increase over time, reaching steady-state the year after deployment is completed. The details of how these benefits are calculated are included in the GD-CEF-EC-2 CEF-EC Business Case (Section 5.2). The reduction in revenue requirements due to the savings would be realized by customers through PSE&G base rate cases. The operational savings will be realized in the following areas and are approximate values through 2037:

1) Customer operations: $567 million of savings due to reduced labor costs given that the iESP remote data and connection capabilities eliminates almost all manual meter reading, some call center roles, and field collection work, and also increases data accuracy of meter reads from 91% to at least 99%, thus reducing the amount of estimated readings and increasing bill accuracy;

2) Grid operations for gas operations and vehicle fleet: $196 million of labor and material due to less work and fewer truck rolls given that the CEF-EC enables remote electric disconnect and reconnect processes. Although this is electric work, resources from gas operations are used to perform these duties.

3) Grid operations for electric operations: $124 million of labor and material savings due to less work and fewer truck rolls given that the CEF-EC enables remote disconnect and reconnect processes, reduces customer power quality visits and investigation, and provides outage management improvements, particularly with regard to nested outages.

Q. Does the CEF-EC Release 1 result in environmental benefits?

A. Yes. The CEF-EC Release 1 program will result in environmental benefits, including putting New Jersey back on track to meet the mandates of New Jersey's Global Warming Response Act,[6] while also reducing air pollution and smog that disproportionally impact the state's urban centers and low-income residents. Specifically, the CEF-EC Release 1 will result in the reduction of carbon dioxide emissions by 2,761 tons through fewer truck rolls. The economic value of these emissions reductions, and of the other EC benefits discussed qualitatively in the EC Business Case, are not included in the benefits quantified in Figure 5 above.

[6] *See N.J.S.A. 26:2c-37 et seq*. The NJ Global Warming Response Act establishes two greenhouse gas limits: the first requires New Jersey by 2020 to reduce greenhouse gas emissions to an amount equal to or below the 1990 level of statewide greenhouse gas emissions; the second requires New Jersey by 2050 to reduce greenhouse gas emissions by at least 80 percent of the 2006 level of statewide greenhouse gas emissions.

Q. Please explain the primary sources of the capital and operational costs.

A. Capital and O&M costs include labor, material, and outside services to deploy the iESP infrastructure. The details of how these costs are calculated are included in the GD-CEF-EC-2 CEF-EC Business Case. The capital costs are primarily derived from estimates from Landis+Gyr for labor and materials to design the network, install new smart meters and network communications infrastructure, and remove the legacy, non-advanced meters. The internal labor costs are estimated by PSE&G for work such as managing the Program, iESP network, and meter integration; testing meters removed from service in accordance with the New Jersey Administrative Code; deploying use case capabilities; and managing change and communications.

Q. Please summarize the proposed amount of investment, level of expenses and Program term.

A. The Release 1 deployment of the meter and communication network will take place over approximately five years extending from January 2019 to March 2024. During this deployment phase, PSE&G proposes to commit approximately $721 million in capital investment. Additionally, the deployments will require O&M expenses of approximately $73 million. The overall CEF-EC budget includes all identified costs necessary to deliver the Program, including smart meter and communications infrastructure, use case deployment, customer education, information technology (“IT”), administration, change management, program management, evaluations, and quality assurance/quality control efforts.

Q. Please summarize the proposed recovery of undepreciated meter balances.

A. Installing electric smart meters in virtually 100% of residential and commercial/industrial customers' residences and businesses means replacing 2.2 million meters. These legacy electric meters have been installed over the last 20 years, but are being depreciated over a 42-year period. As explained in greater detail in Ms. Powell's testimony, the net book value as of June 30, 2018 is $219 million and will continue to decline as they are depreciated. Additionally, the value will be impacted by any changes in depreciation rates set in the pending base rate case. Retirements of such a large plant balance is an extraordinary event that warrants special regulatory treatment to ensure appropriate recovery.

Q. How will PSE&G recover the CEF-EC Program costs?

A. PSE&G seeks to recover the capital cost of the iESP through a cost recovery mechanism consistent with the IIP regulations. Also, pending approval to defer them as regulatory assets, the project O&M and stranded asset costs will be included in the next PSE&G base rate case as a fixed revenue amount over a five-year period. Details are provided in the testimonies of Mr. Swetz and Ms. Powell.

VI. CUSTOMER SERVICE METRIC IMPROVEMENT

Q. PSE&G has an on-going effort to improve a number of customer service metrics and report this to the Board. How does AMI impact this effort?

A. There are eight metrics that PSE&G currently shares with the Board and Rate Counsel on a quarterly basis. The metrics are listed below with a description of the impact from AMI post deployment:

1. Average Speed of Answer Within 30 Seconds: will benefit due to lower call volumes.
2. Abandoned Call Rate: will benefit due to lower call volumes.
3. Speed of Customer Response Average in Seconds: will benefit due to lower call volumes.
4. Percent of On-Cycle Meter Reads: significant benefit due to expected 99.0 percent read rate.
5. Rebills/1,000 Customers: significant benefit due to virtual elimination of estimated bills and manual reads.
6. Gas Leak/Odor Response Within 60 Minutes: no impact because near 100%.
7. Percent of Customer Service Appointments Met: will benefit from the freeing up of resources due to decreases in service appointments related to disconnects and reconnects and initial and final meter reads.
8. Escalated Complaints to the BPU/1,000 Customers: will benefit due to increased accuracy and timeliness of meter reads and billing.

VII. PSE&G IESP TECHNOLOGY AND DEPLOYMENT MATURITY

Q. Is smart metering truly an established technology in the utility industry?

A. Yes, it is. According to a December 2017 report from the Federal Energy Regulatory Commission ("FERC") entitled the "Assessment of Demand Response and Advanced Metering," the number of smart meters in the United States grew almost ten-fold from 2007 to 2015.[7] A review of 2016 U.S. Energy Information Administration ("EIA") data demonstrates that the number of smart meters deployed nationwide has increased to more than 70 million, which accounts for approximately 47% of utility customers.

Q. Please summarize how New Jersey compares to other states in terms of smart device and infrastructure deployment and maturity.

A. As of the end of 2016 and illustrated below (Figure 6):

- New Jersey has less than 50,000 smart meters deployed and is 47th out of 50 states in terms of smart meter penetration.[8] There are no smart meters installed for residential customers in PSE&G's service territory.
- As shown in Figure 6 below, only three states other than New Jersey have less than 1% smart meter penetration: West Virginia, New York, and Rhode Island. However, New York's Reforming the Energy Vision (NY REV[9]) will lead to widespread AMI adoption in short order in that state. This will leave New Jersey, Rhode Island, and West Virginia as the last three states that do not have a significant smart meter deployment program.[10]

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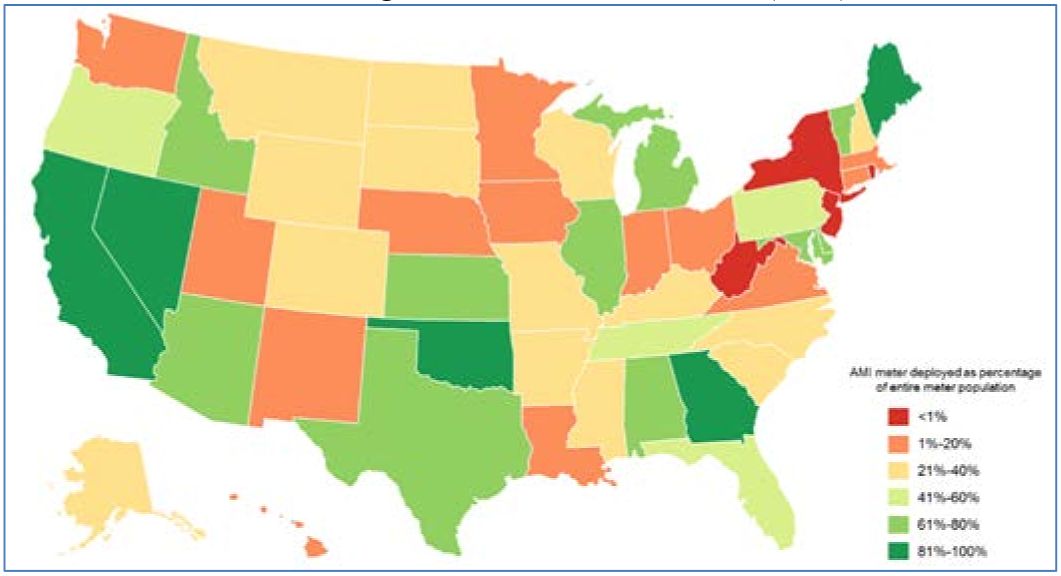
7 https://www.ferc.gov/legal/staff-reports/2017/DR-AM-Report2017.pdf.

8 https://www.eia.gov/electricity/data/eia861/.

9 https://static1.squarespace.com/static/576aad8437c5810820465107/t/5aec725baa4a99171e5890d4/1525445212467/REV-fm-fs-1-v8.pdf.

10 PSE&G is aware of Rockland Electric Company's ("RECO") initiative to install approximately 72,000 smart meters throughout its electric service territory in New Jersey; however, even taking the RECO program into account, New Jersey still remains far behind nearly the entire country with respect to AMI penetration.

Figure 6 – US AMI Penetration (2016)



Q. Is PSE&G already purchasing smart meters?

A. It will begin to do so shortly. The electric meter replacement process is still operating pursuant to current policies and procedures, which currently results in a new AMR meter being installed to replace an aging meter. PSE&G will change this policy shortly to use smart meters instead of AMR meters for the reasons listed below.

- The costs for electric AMR and smart meters have now equalized. The AMR manufacturer no longer produces the meters PSE&G has been installing for almost two decades. We would need to purchase a significantly more expensive meter to keep the AMR functionality.
- Given the desire to move to iESP, continuing to install AMR may increase stranded costs.
- Approximately 700,000 electric meters will need to be replaced soon given the length of time that they have been in service.

- The timing for electric AMI deployment coincides with full deployment of AMR in PSE&G's gas service territory, meaning customers who receive electric and gas service from the Company would benefit from automated meter reading for both services.

The factors listed above make it prudent to begin purchasing and installing smart electric meters once the Company's current stock of AMR meters is installed. The extended functionality of the smart meter will be turned off until such time as the iESP network is operational and the Board approves PSE&G's request through this filing.

Q. Given that AMI deployment is common throughout the country, what research has PSE&G done with respect to AMI deployment best practices?

A. The Company has done extensive research surrounding best practices for AMI deployment. For example, it has:

- Gathered information from other utilities that have deployed AMI, *e.g.*, RECO, ConEd, PECO, and Ameren;
- Worked with consultants that have experience in AMI deployments, *e.g.*, PA Consulting Group, Z2Solutions, Accenture, IBM, Navigant and First Quartile;
- Partnered with Landis+Gyr, which is a leading global provider in AMI infrastructure and services; and
- Reviewed industry business cases (*e.g.*, RECO, ConEd, PECO and Ameren) and a DOE AMI implementation report.

PSE&G's CEF-EC Business Case incorporates key takeaways and validations from these activities.

VIII. <u>PSE&G CEF-EC RELEASE 1 – COMMUNICATIONS STRATEGY</u>

Q. How does PSE&G plan to engage with and support customers before, during, and after deployment of the PSE&G Energy Cloud - Release 1?

A. PSE&G has created a Customer Engagement Strategy ("Strategy") that identifies the means by which the Company will develop and execute a Customer Engagement Plan (the "Plan"). *See* Schedule GD-CEF-EC-3.

PSE&G will utilitze existing PSE&G associates in the Customer Outreach Group as part of the organization that will be mobilized to support the CEF-EC Release 1 deployment. The Customer Outreach Group will develop and execute the Plan with the assistance of existing groups within the Company, such as Campaign Management, Governmental Affairs, and Corporate Communications.

While the Plan will address communications following BPU approval of the Energy Cloud Program, PSE&G will begin communicating with customers and other stakeholders about the Energy Cloud as soon as the Company submits the filing. These communications will be done on an ongoing basis across a myriad of channels through the filing process and are intended to, among other things, make customers, key stakeholders, and employees aware that PSE&G has filed the Energy Cloud Program, and identify the objective and need for the Energy Cloud Program.

These communications will be developed and delivered by the Campaign Management, Governmental Affairs and Corporate Communications.

The Strategy provides an overview of a series of five customer communications to facilitate a successful deployment that keeps customers informed at each step of the CEF-EC implementation. These communications will take place following approval by the BPU and continue into the post-deployment period. The five communications include:

1. A post-BPU approval press release introducing the CEF-EC, noting its approval, and laying out the initial steps for implementation;
2. Communications educating customers about the benefits of the CEF-EC;
3. Communications addressing customer concerns, including: (a) proactively responding to anticipated customer concerns around meter safety and data privacy; and (b) reactive communications with customers;
4. Communicating the smart meter deployment schedule to customers, and continuing to inform them of the CEF-EC benefits; and
5. Addressing concerns initiated by customers resulting from the installation of smart meters.

For each of the five customer communications, the Strategy makes specific suggestions about the objectives, key messages, audience, communication channels, and supporting materials.

IX. <u>STAFFING IMPACTS & PLAN</u>

Q. Would approval of the CEF-EC impact the Company's staffing?

A. Yes. Smart meters will obviate the need for meter readers, as well as their management and certain support personnel (such as billing and call center personnel). PSE&G has identified opportunities for any permanent employee displaced by AMI to transition into new roles elsewhere within the Company that will become available because of attrition through the end of deployment in 2025.

X. PSE&G CEF-EC RELEASE 1 – TECHNOLOGY ARCHITECTURE IMPACTS

Q. Please explain the IT implications of the CEF-EC.

A. The deployment of the CEF-EC, smart meters, communications network, and the availability of significantly more granular volumes of quality network and customer data (including daily usage, voltage, load, connectivity, and alerts) will impact the Company's IT systems. Core applications, data, hardware, software, communications and security technology platforms in place will be impacted, particularly with the eventual transition from static to near real-time operations in both network and customer areas.

The Program will rely heavily on technology infrastructure to enable the smart use cases on the roadmap. The iESP includes a two-way communications network, capabilities to collect and analyze operational and customer data, connection "adapters" to other networks, and an application environment in which multiple services and applications can be developed for customers and the Company. The iESP will include prudent data access and cybersecurity components to support information protection, data privacy, and operational continuity.

XI. INFRASTRUCTURE INVESTMENT PROGRAM REGULATIONS

Q. What are the IIP regulations?

A. They are regulations adopted by the BPU "to provide a rate recovery mechanism that encourages and supports necessary accelerated construction, installation, and rehabilitation of certain utility plants and equipment." *See* N.J.A.C. 14:3-2A.1(b).

Q. Is the CEF-EC eligible under the IIP proposal?

A. Yes. As stated in the IIP regulations, specifically in N.J.A.C. 14:3-2A.2(a), eligible projects within an IIP shall be:

1. Related to safety, reliability, and/or resiliency;
2. Non-revenue producing;
3. Specifically identified by the utility within its petition in support of an Infrastructure Investment Program; and
4. Approved by the Board for inclusion in an Infrastructure Investment Program, in response to the utility's petition.

The CEF-EC meets all of these criteria. In addition, the IIP regulations list examples of projects that fall within their scope, which includes "[e]lectric distribution automation investments, including, but not limited to. . .voltage and reactive power control [and] communications networks[.]" N.J.A.C. 14:3-2A.2(b)(4). The CEF-EC Program establishes the communication network that enables the electric distribution automation described in the use cases. Moreover, Use Case #18 gives PSE&G the opportunity to determine with better efficiency where voltage violations exist, both above and below nominal voltage. PSE&G is requesting Board approval to implement the CEF-EC, which is consistent with the IIP policy and in the best interests of its customers and New Jersey.

Q. Are there minimum filing requirements associated with seeking accelerated recovery of infrastructure investments under the IIP regulations?

A. Yes. The location in the CEF-EC filing of all requirements under the IIP regulations is provided in Appendix A to the Petition. I address the requirements related to program eligibility, capital expenditures, selection criteria, cost-benefit analysis, and reporting for the proposed investments. Mr. Swetz will address requirements associated with cost recovery.

Q. Is the Company proposing base capital expenditures on electric distribution projects similar to those proposed for the CEF-EC?

A. Yes. Consistent with the IIP rules, the Company commits to base rate treatment of investments in an amount at least 10 percent of the capital expenditures recovered through the recovery mechanism proposed for the CEF-EC. These capital expenditures will be on work similar to that proposed to be recovered under the CEF-EC recovery mechanism. This is shown on Schedule GD-CEF-EC-4B.

Q. Is the Company proposing annual baseline spending levels over the life of the Program?

A. Yes. Please see Schedule GD-CEF-EC-4B.

Q. What is the justification for the annual baseline budget spending levels?

A. The annual baseline spending levels proposed in Schedule GD-CEF-EC-4B are the Company's projected baseline capital budget, along with an amount of proposed base rate recovery spending on work that is similar to that which is being proposed for the CEF-EC cost recovery mechanism. The annual baseline spend total plus the proposed additional "similar work" provides for the required capital expenditures.

Q. Is the Company proposing any limit to variations in annual spending?

A. Yes. Consistent with the IIP regulations, the Company proposes that it be allowed annual variations in its capital expenditures up to 10 percent so long as the expenditures do not exceed the overall approved budget for the CEF-EC. The Company will seek Board approval for any year-to-year variances that are expected to be greater than 10 percent.

Q. Have you included the Company's actual capital expenditures over the past five years and projected capital expenditures over the next five years by major category?

A. Yes. Please see Schedule GD-CEF-EC-4A for the actual capital expenditures by major category from 2012-2017, and Schedule GD-CEF-EC-4B for the projected electric capital expenditures by major category from 2019 through 2023.

Q. Has an evaluation been done to determine the CEF-EC projects, in-service dates, costs and benefits of the proposed Program?

A. Yes. Please see my testimony above and the EC Business Case (Schedule GD-CEF-EC-2).

Q. Have you developed an annual budget for the CEF-EC?

A. Yes. Please see Schedule GD-CEF-EC-5 for the monthly and annual capital expenditures for the Program.

Q. Is the Company proposing any reporting requirements associated with the CEF-EC?

A. Yes. Consistent with the IIP regulations, the Company proposes to submit semi-annual status reports to Board Staff and the Division of Rate Counsel consistent with N.J.A.C. 14:3-2A.5(e).

XII. CONCLUSION

Q. Do you have any concluding statements?

A. Yes, the proposed CEF-EC Release 1 represents a significant first step towards making New Jersey a leader in smart energy. As set forth above, the CEF-EC is a customer-focused, cost-effective Program that will set the stage for even further technological advances for utilities in the future. PSE&G requests that the Board approve the CEF-EC.

Q. Does this conclude your testimony at this time?

A. Yes.

CREDENTIALS
OF
GREGORGY C. DUNLAP
VICE PRESIDENT CUSTOMER OPERATIONS

My name is Gregory ("Greg") Dunlap and I am employed by Public Service Electric and Gas Company ("PSE&G" or the "Company") as the Vice President, Customer Operations. My business address is 80 Park Place, Newark, NJ 07102. I have held this position since July 2014. In this position, I have primary management and oversight responsibility for all customer-facing operations, including customer satisfaction, customer contact, billing, metering, and collections.

EDUCATIONAL BACKGROUND

I have a Bachelor of Science degree in engineering from Rutgers University – College of Engineering; a Masters of Business Administration degree from Farleigh Dickinson; and a Masters in Divinity degree from New Brunswick Theological Seminary. I earned my Certified Energy Manager credential from the American Association of Energy Engineers in 2009.

WORK EXPERIENCE

I have worked for PSE&G for over 35 years, and have a broad background in Utility Sales & Marketing, Customer Operations, the Appliance Service Business, Government Relations, and Public Affairs. I also led PSE&G's

efforts to educate our customers about energy choice, during the deregulation of the electric and gas industries in New Jersey.

Prior to my current role, I was PSE&G's Director - Customer Operations & Account Management, responsible for key account management, customer relations, customer satisfaction measurement, new construction (electric and gas) project management, and utility sales.

NEXT GENERATION SMART UTILITY: THE ENERGY CLOUD

PUBLIC SERVICE ELECTRIC & GAS COMPANY (PSE&G)

October 11, 2018

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LIST OF FIGURES

ACRONYMS

ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
AMR	Automated Device Reading
BEMS	Building Energy Management System
BU	Bargaining Unit
CBS	Consumer Behavior Studies
CCST	California Council on Science and Technology
CIS	Customer Information System
CPP	Critical Peak Pricing
CPR	Critical Peak Rebates
CRC	Circuit Reconfiguration Controller
CVR	Conservation Voltage Reduction
DER	Distributed Energy Resources
DLC	Direct Load Control
DMS	Distribution Management Systems
DOE	Department of Energy
EIA	Energy Information Administration
EMS	Energy Information Management System
ETR	Estimated Time of Restoration
EV	Electric Vehicle
FIPS	Federal Information Processing Standard
FCC	Federal Communications Commission
FLISR	Fault Location, Isolation, and Service Restoration
HAN	Home Area Networks
HEMS	Home Energy Management Systems
HVAC	Heating, Ventilation and Air Conditioning
IHD	In-Home Displays
iESP	Intelligent Energy Services Platform
IoT	Internet of Things
IT/OT	Information Technology / Operational Technology
LED	Light-emitting Diodes
LIDAR	Light Detection and Ranging
MAMR	Mobile Automatic Device Reading
MDMS	Device Data Management System
NIST	National Institute of Standards and Technology
O&M	Operation and Maintenance (Costs)
OMS	Outage Management System
OTA	Over the Air
PCT	Programmable Communicating Thermostats
POC	Proof of Concept
PSE&G	Public Service Electric & Gas

PV	Photovoltaic
RF	Radio Frequency
ROI	Return on Investment
RBAM	Risk Based Asset Management
RTP	Real-time Pricing
SAIDI	System Average Interruption Duration Index
SCADA	Supervisory Control and Data Acquisition
SDI	Smart Devices & Infrastructure
SGIG	Smart Grid Investment Grant
TOU	Time-of-Use
VO	Voltage Optimization
VOI	Value of Investment
VPP	Variable Peak Pricing
VVC	Volt/VAR Control
VVO	Volt/VAR Optimization

DEFINITIONS

Advanced Distribution Management System (ADMS): the software platform that supports the full suite of distribution management and optimization. An ADMS includes functions that automate outage restoration and optimize the performance of the distribution grid.

Advanced Metering Infrastructure (AMI): full measurement and collection system that includes devices at the customer site, communication networks between the customer and a service provider (such as an electric, gas, or water utility) and data reception and management systems that make the information available to the service provider.

Agile: an approach to system and process implementation that is focused on the iterative and rapid delivery of results. It is founded on the concept of early customer involvement, with the customer represented by members integrated into the project team. Agile replaces detailed requirements documents with an iterative discovery of detailed requirements through prototyping and rapid development activities. Agile accepts and even promotes changes in requirements through the discovery process.

Automated Device Reading (AMR): technology of automatically collecting consumption, diagnostic, and status data from water device or energy metering devices (gas, electric) and transferring that data to a central database for billing, troubleshooting, and analyzing.

Building Energy Management System (BEMS): computer-based systems that help to control, monitor, measure and optimize building technical services and the energy consumption of devices used by the building.

California Council on Science and Technology (CCST): an independent, not-for-profit 501 (c) (3) organization designed to offer expert advice to the California state government and to recommend solutions to science and technology-related policy issues.

Circuit Reconfiguration Controller (CRC): a controller that is able to perform fault isolation calculations based on communications with SCADA and the OMS in order to reconfigure a circuit and isolate a fault.

Conservation Voltage Reduction (CVR): is an energy conservation technique that reduces the incoming voltage to buildings and homes without effecting the power quality or capacity.

Consumer Behavior Studies (CBS): study that involved time-based rate programs and use of statistically rigorous randomized and controlled experimental designs for estimating impacts and benefits of utility consumers.

Critical Peak Pricing (CPP): a construct under which a utility can call a critical event and raise the rate when it anticipates or experiences high wholesale market prices or emergency system conditions.

Critical Peak Rebates (CPR): offered when a utility calls a critical event during pre-specified time periods in response to anticipated or observed high wholesale market prices or emergency system conditions.

Customer Information System (CIS): a complete customer relationship management application that allows the user to define a virtually unlimited number of fields and codes in addition to the large number of predefined information.

Department of Energy (DOE): a cabinet-level department of the United States Government concerned with the federal policies regarding energy and safety in handling nuclear material.

Direct Load Control (DLC): when a utility signals a customer's appliance to stop operations (to reduce the demand for electricity).

Distributed Energy Resources (DER): distributed generation, also distributed energy, on-site generation or district / decentralized energy is electrical generation and storage performed by a variety of small, grid-connected devices referred to as distributed energy resources.

Distribution Management Systems (DMS): a collection of applications designed to monitor & control the entire distribution network efficiently and reliably.

Energy Information Administration (EIA): a principal agency of the U.S. Federal Statistical System responsible for collecting, analyzing, and disseminating energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment.

Energy Information Management System (EMS): a system of computer-aided tools used by operators of electric utility grids to monitor, control, and optimize the performance of the generation and/or transmission system. The computer technology is also referred to as SCADA/EMS or EMS/SCADA.

Estimated Time of Restoration (ETR): an indication of the time at which a utility will restore service to a customer or customers experiencing an outage.

Fault Location, Isolation, and Service Restoration (FLISR): a collection of tools used for detection, location, and isolation of faults and restoration of supply for de-energized customers. FLISR can be used in manual, semi-automatic, and automatic mode.

Federal Communications Commission (FCC): regulates interstate and international communications by radio, television, wire, satellite, and cable in all 50 states, the District of Columbia and U.S. territories.

Federal Information Processing Standard (FIPS): publicly announced standards developed by the United States federal government for use in computer systems by non-military government agencies and government contractors.

Home Area Network (HAN): a network contained within a user's home that connects digital devices that are wired into the network, including multiple computers and their peripheral devices, telephones, VCRs, televisions, video games, home security systems, smart appliances, fax machines, and other digital devices.

Home Energy Management System (HEMS): a system which allows a user to track energy use in detail to better save energy. For instance, a customer can see the energy impact of various appliances and electronic products simply by monitoring his or her HEMS while switching individual devices on and off.

Heating, Ventilation and Air Conditioning (HVAC): system is used to provide heating and cooling services to buildings.

In-Home Displays (IHD): display which communicates with Smart Devices, giving consumers unprecedented insight into their energy usage and costs.

Information Technology / Operational Technology (IT/OT): Information technology generally covers corporate systems and networks (Customer, Billing, Finance, Local Area Network). Operational technology covers operations and electricity network systems and infrastructure (SCADA, AMI, ADMS);

Intelligent Energy Services Platform (iESP): an ecosystem based on a foundation of smart communications networks and devices that provide significant amounts of data and functionality and have helped users realize and/or prepare to support a broad range of programs that enable a range of capabilities.

Internet of Things (IoT): the interconnection via the Internet of computing devices embedded in everyday objects, enabling them to send and receive data.

Light Detection and Ranging (LIDAR): a remote sensing method that uses light in the form of a pulsed laser to measure ranges (variable distances).

Light-emitting Diodes (LED): a two-lead semiconductor light source.

Meter Data Management System (MDMS): refers to software that performs long-term data storage and management for the vast quantities of data delivered by smart device systems.

Mobile Automatic Device Reading (MAMR): where a reading device is installed in a vehicle enabling a device reader to obtain device reads by driving the vehicle while the reading device automatically collects the device readings.

National Institute of Standards and Technology (NIST): a measurement standards laboratory that is a non-regulatory agency of the United States Department of Commerce.

Operation and Maintenance (O&M): in the context of this report these are the costs to operate and maintain utility operations.

Outage Management System (OMS): a computer system used by operators of electric distribution systems to assist in restoration of power.

Over the Air (OTA): a standard for the transmission and reception of application-related information in a wireless communications system.

Photovoltaic (PV): relating to the production of electric current at the junction of two substances exposed to light.

Programmable Communicating Thermostats (PCT): programmable thermostats that can receive information wirelessly.

Proof of Concept (POC): evidence, typically derived from an experiment or pilot project, which demonstrates that a design concept, business proposal, etc., is feasible.

Public Service Electric & Gas Company (PSE&G): a public utility, which is New Jersey's largest provider of electric and gas service – serving 2.2 million electric customers and 1.8 million gas customers.

Radio Frequency (RF): any of the electromagnetic wave frequencies that lie in the range extending from around 20 kHz to 300 GHz, roughly the frequencies used in radio communication.

Real-time Pricing (RTP): rate which charges customers prices based on real-time market rates on an hourly or other interval basis, allowing consumers to adjust their electricity usage accordingly; for example, scheduling usage during periods of low demand to pay cheaper rates.

Return on Investment (ROI): the ratio between the net profit and cost of investment resulting from an investment of some resource.

Risk Based Asset Management (RBAM): couples risk management, standard work, and condition-based maintenance to properly apply resources based on process criticality. This ensures that proper controls are put in place and reliability analysis is used to ensure continuous improvement.

Smart Grid Investment Grant (SGIG): program aimed to accelerate the modernization of the nation's electric transmission and distribution systems.

Supervisory Control and Data Acquisition (SCADA): a control system architecture that uses computers, networked data communications, and graphical user interfaces for high-level process supervisory monitoring and management, using peripheral devices such as programmable logic controllers and discrete proportional–integral–derivative controllers to interface to the process plant or machinery.

System Average Interruption Duration Index (SAIDI): a system index of average duration of interruption in the power supply indicated in minutes per customer.

Time-of-Use (TOU): a rate plan where customers are charged higher rates for the energy they use during specified peak demand times.

Value of Investment (VOI): measures the total value of "customer" or intangible benefits derived from technology initiatives in addition to the "operational" benefits measured by ROI.

Variable Peak Pricing (VPP): a hybrid of time-of-use and real-time pricing where the different periods for pricing are defined in advance, but the price established for the on-peak period varies by utility and market conditions.

Voltage Optimization (VO): an energy saving technology that is used to regulate, clean, and condition the incoming power supply in order to reduce the voltage supplied to the optimum level for the on-site electrical equipment and appliances.

Volt/VAR Control (VVC): refers to the process of managing voltage levels and reactive power (VAR) throughout power distribution systems.

01

EXECUTIVE SUMMARY

1 EXECUTIVE SUMMARY

1.1 INTRODUCTION

Public Service Electric & Gas Company (PSE&G) serves 2.2 million electric customers and 1.8 million gas customers with safe, reliable, and cost-effective utility services. Since its founding in 1903, PSE&G has consistently put the needs and desires of all its customers and the state of New Jersey in the forefront of its objectives. PSE&G remains one of the top performing utilities in the nation, but lags behind its peers in terms of modernizing its grid through the deployment of intelligent infrastructure. Recently, the industry landscape for distribution utilities has been evolving to adapt to and accommodate the changing expectations of its customers and stakeholders. Utility customers and other stakeholders such as state regulators, government, environmental groups, third party service providers, etc. have become more educated and technologically savvy, resulting in increased demand for enhanced capabilities, which improve engagement, efficiency, transparency, and the environment. Today's customers expect near real-time visibility of their energy usage, choices in their energy provider, preferred time-of-use rates to reduce energy costs, access to new markets and services, and 'clean' energy options that reduce their carbon footprint.

The evolving expectations and desires of customers and other stakeholders in New Jersey are a manifestation of the past and ongoing transformation of energy delivery and consumption options, many of which are informed by developments across the United States and abroad. The movement towards sustainable consumption that has been in play over the past few decades is maturing and spurring new developments. Distributed ecosystems such as distributed energy resources (DERs), storage, microgrids, etc. are increasingly prevalent components of advanced energy markets that incorporate multidirectional flows of electricity and are supported by multidirectional flows of information. Furthermore, utilities are deploying increasingly automated command and control systems to enhance system planning and operations in support of these distributed energy market ecosystems and to promote increased reliability and service restoration following interruptions.

These developments and other initiatives being tested elsewhere around the world such as smart cities, utility operations process automation through the use of Bots, and self-healing grids, to name a few, will eventually spur further innovation in New Jersey and the communities served by PSE&G. Customer and stakeholder expectations will continue to evolve as they perceive these capabilities to be the new normal.

Leading utilities across the country are implementing innovative technology including Intelligent Energy Service (infrastructure and data) Platforms (iESPs), updating processes, and training employees in order to meet the needs of their customers and other stakeholders and lay the groundwork for developing the Energy Cloud of the future. iESPs represent the foundation upon which the Energy Clouds will be constructed and are comprised of technology layers including smart communications networks, devices, security, application, and data services. The Energy Cloud is expected to provide significant amounts of data and functionality and have helped utilities realize and/or prepare to support a broad range of benefits including, but not limited to:

- Laying a foundation for a range of comprehensive new energy products and services, which can further enhance consumer choice and control for all customers.
- Enable future smart utility enabled capabilities that provide stakeholders the means to make informed choices as to their energy consumption, support related and tertiary technology deployment on behalf of customers, communities and the state of New Jersey, and improves utility operations by providing significantly more discrete insight into the distribution network.
- Improve outage detection and response that are faster than ever before; identifying nested outages ensures that power restoration becomes easier and more efficient, allowing customers to experience shorter outages and allows the utility to have a more secure and resilient energy system with flexibility on the demand side.
- Incenting consumers to reduce demand (and usage) by providing near real-time information on cost and usage, and offering new innovative rates and program, thereby encouraging consumers to reduce their demand, directly contributing to lower energy consumption and bills, energy efficiency, and carbon emission reductions.
- The energy cloud enables more engaged and active energy consumers and facilitates faster switching and potential peer-to-peer distribution markets. This, in turn, leads to a more dynamic and competitive retail energy market and innovation in products and services.
- Smart devices also enable more efficient operations for both energy suppliers and network operators, unlocking savings that will translate into lower bills for households, businesses and communities.
- Smart device data, subject to appropriate data privacy and access control arrangements, enables more sophisticated tariff structures and energy demand management approaches.

PSE&G's goal is to establish a business and technology operating model that enables a number of customer, community, and company smart energy capabilities, or "use cases." At the core of this Program is the deployment of advanced metering infrastructure ("AMI"), comprised of approximately 2.2 million electric "smart" meters, as well as communications and back-office systems. The initial deployment of PSE&G Energy Cloud ("Release 1") will be an installation of an intelligent energy service platform ("iESP") across the Company's electric service territory, and the initiation of 22 foundational and advanced capabilities or "use cases" that will make use of and maximize the value of the iESP. The iESP will be the foundational component of the company's new Energy Cloud that underpins the company's transition towards a smart utility of the future that benefits all parties in New Jersey. This report has been developed to lay out the broad case for and the means by which this change will be realized and identifies which benefits are expected to be realized in the near-term as a result of iESP enabled energy cloud deployment.

1.2 VISION AND OBJECTIVES

In order to handle future operational variability and customer expectations, utilities will need to deploy pervasive digital networks that support the collection of large amounts of data that, when combined with advanced technologies like artificial intelligence, will support complex operations and tailored customer services.

Over the next decade, the electrification of transportation, the introduction of distributed resources, and the increase in customer expectations for predictive and tailored services will require utilities, the Board of Public Utilities, and other stakeholders to reinvent the electric power value chain, from generation and operations to new products and services.

In order to handle the operational variability introduced by electric vehicles (EVs) and DERs, operators will rely on pervasive, intelligent digital networks that support complex operations while engaging individuals, entities, and communities in personalized and frictionless services that fit their lifestyles and aspirations.

"The PSE&G Energy Cloud incorporates scalable, secure, safe and reliable iESP infrastructure and data in a cost-effective, customer-centric and stakeholder supportive manner to establish platform and data services that enable deployment of PSE&G foundational, advanced and future smart utility capabilities for the benefit of all customers and communities in New Jersey"

This will be achieved through the deployment of technologies like advanced sensors, two-way communication networks, IoT platforms, and customer engagement solutions deployed on foundational iESPs. Those platforms will evolve over time and progressively offer a range of expanded and enhanced energy products, services and capabilities that will deliver societal and economic value for customers and communities.

This vision and plan, over a 20-year time period, will realize significant societal and economic value for all PSE&G customers, communities, cities and New Jersey, and enable PSE&G to become best in class across its customer and grid operations.

The PSE&G Energy Cloud and its foundational iESP will support six key capabilities that will spur the company's evolution towards a next generation utility and New Jersey's smart state IoT-enabled future:

1. Smart Operations – a reliable and customer-centric utility where automated operations, tailored and predictive customer experience, and service flexibility are the norm.

SMART OPERATIONS

Supports a reliable and customer-centric utility where automated operations and processes, tailored and predictive customer experience, and service flexibility are the norm. The proposed development will enable increased customer service and efficiency and improved operational performance through a number of smart capabilities that leverage smart meter data and new technologies like process automation, robotics and artificial intelligence, to enable enhanced understanding of real time operational status and performance. Customer experience and knowledge will be greatly enhanced using more detailed customer data like daily usage, voltage profiles and smart appliance information in: (a) the PSE&G call centers and operations; and (b) increasing accuracy of bills, customer visibility of their energy consumption, and enhanced self-service.

2. Smart Network – continued operational excellence in a less predictable and more complex electric distribution network.

SMART NETWORK

The historically predictable, linear electric distribution model is evolving into a distributed network of variable sources of energy and demand points. The evolution is driven by distributed energy resources ("DERs") reaching critical mass, main stream electrification of transportation, and prevalence of microgrids and storage resources across the service area and to all customer types The ECP will enable better reliability and increased customer service for PSE&G customers through deploying distributed intelligence sensors, controllers, and communications to "see" and "control" the real time operational status and performance of its network.

3. Smart Customer – place customers at the center of the company's universe through the provision of data and the means to understand and take ownership of their energy consumption.

SMART CUSTOMER

In today's digital world, the interaction between utility companies and customers is increasingly influenced by companies in other sectors, not simply other utilities. Companies that currently provide an effortless customer experience (service and mobile applications), such as Amazon and Netflix, have become integral to many customers' daily activities and the benchmark for convenience and service. This means that customers will welcome, and ultimately require, higher levels of engagement with their utility and energy usage through capabilities that the ECP enables. These include full visibility of customers' energy usage, tools to help them with efficiency, bill alerts, services delivered by home assistants, solar and electric vehicle support, and choice of a range of tailored rate options.

4. Smart Home – provide universal access to many advanced services as the home becomes increasingly connected, robotized, and "smart".

SMART HOME

The Smart Energy Home includes all smart appliances (washers, dryers, refrigerators), smart home safety and security systems (sensors, monitors, cameras, and alarm systems), and smart home energy equipment (smart thermostats and smart lighting). ECP makes smart homes possible by providing convenience and sustainability, as connected devices can optimize lighting, temperature, EV charging, and other end uses of electricity.

5. Smart Products & Services – provide an open platform for PSE&G and others to develop and offer products and services to a shared customer base.

SMART PRODUCTS & SERVICES

In response to customer needs, many utilities and non-utilities are leveraging smart infrastructure, sensors, and data to develop new digital products and service offerings, often with business partners, and particularly in the context of the smart customer and home. The ECP makes integration of smart products and services possible. Examples include in-home networks (IHN); appliance monitoring and service; safety and security management; DER facilitation (where PSE&G could assist customers with sizing and locations of solar or EV charging), and innovative time, capacity and DER based rates.

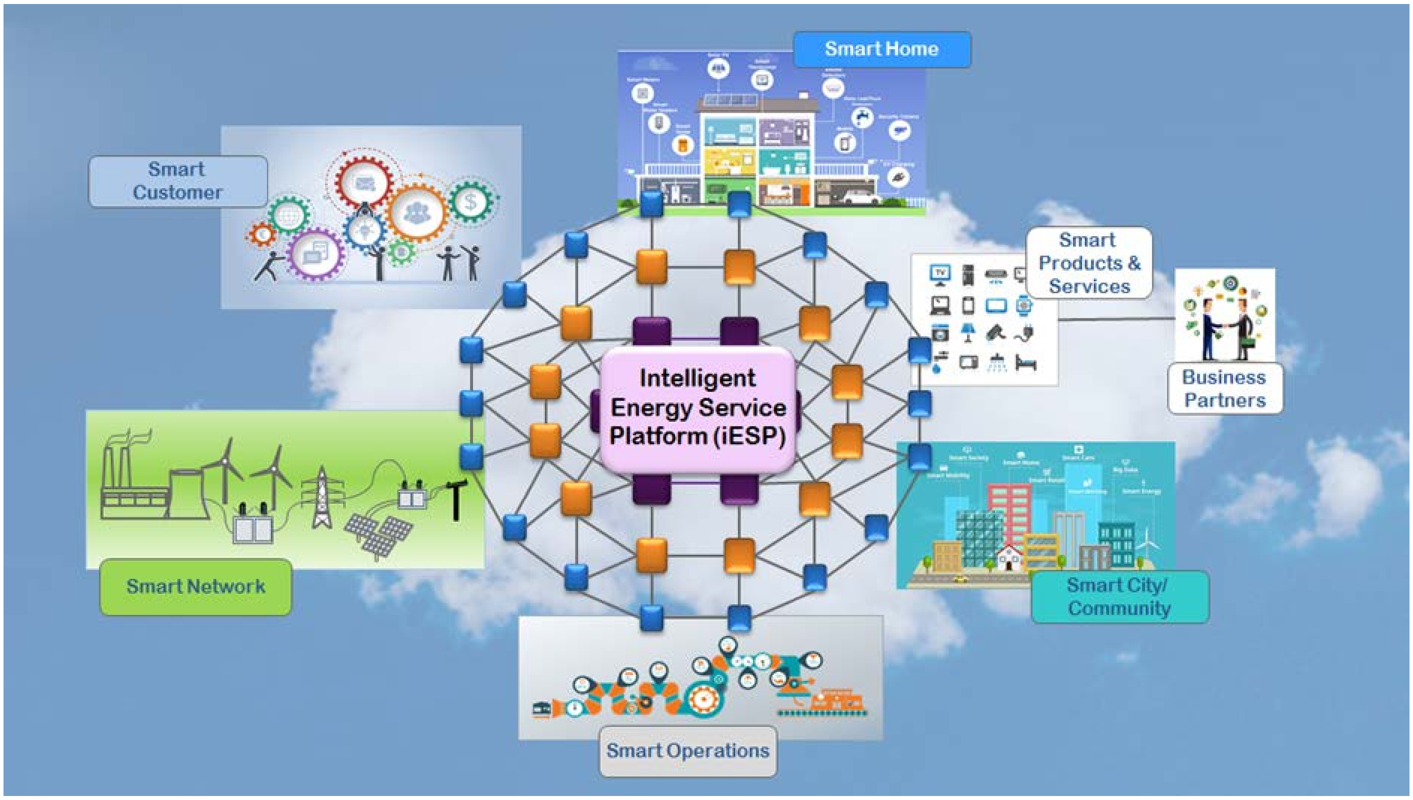
6. Smart City – support 'Smart Cities', accommodate electrified transportation, develop sustainable practices, and offer advanced services.

SMART CITY

A Smart City is an urban area that harnesses digital technology to create a sustainable and intelligent infrastructure. In a Smart City, various smart devices connected to the network (i.e., Internet of Things) can manage energy use, control lighting, manage traffic, analyze air quality, communicate with citizens, and otherwise optimize the efficiency of city operations. Through the CEF-EC, PSE&G would play a supporting role by providing network and data services to support these types of Smart City initiatives.

The graphic below encapsulates the capabilities of the PSE&G Energy Cloud.

Figure 1-1: PSE&G Energy Cloud



Supporting PSE&G's Energy Cloud vision are a number of fundamental objectives:

- The customer is at the core of all energy cloud capability development.
- Ensure the PSE&G Energy Cloud design considers and establishes the foundational components required to enable future smart utility capabilities over a 10-20 year horizon.
- Align and plan smart utility capability deployment with corporate goals and initiatives around an advanced distribution management system (ADMS), volt/VAR optimization (VVO), digitization, renewables, enhanced products and services, and customer engagement.
- Adopt a program-level value-based approach to smart utility strategy and roadmap governance.
- Deploy use case capability in a managed (proof of concept (POC) -> Pilot -> Production) Agile manner according to the program roadmap.
- Ensure that the smart utility capabilities enable operational and customer innovation yet still retain integrity and solid performance around core business needs.
- Incorporate formal data quality and governance processes into overall program governance.
- Adopt an optimized "best of breed" approach to use case solution selection and deployment.
- Leverage current technology and data capabilities where possible.
- Manage the transition to a new operating analytics capability using collaborative change management, and effective and timely communications.

1.3 U.S. GRID MODERNIZATION AND PSE&G

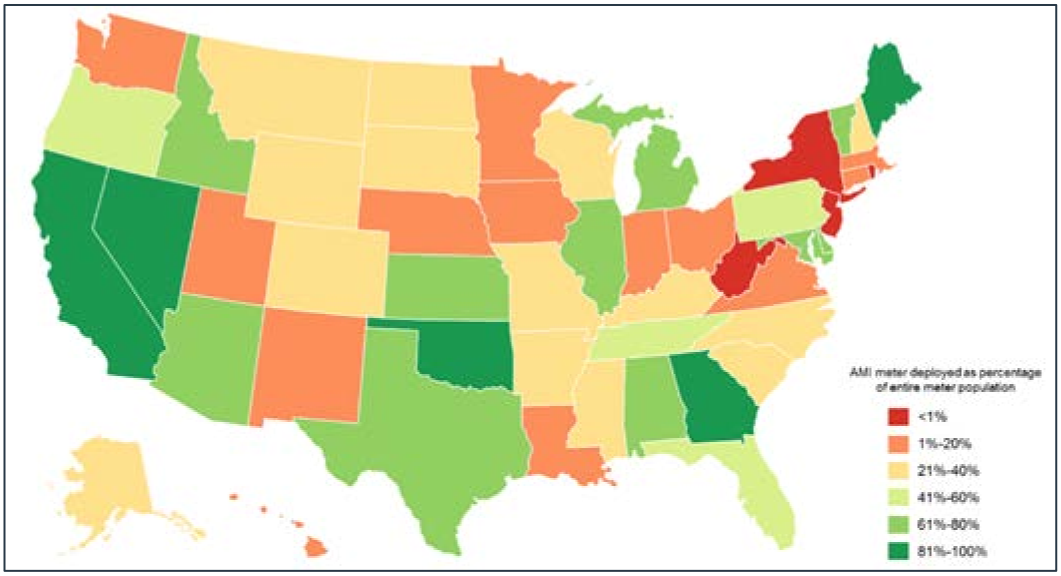
Ensuring that the PSE&G Energy Cloud is not overly ambitious relative to its utility peers is a key consideration. To this end, it is important to understand where PSE&G stands from a smart utility or grid modernization perspective based on the vision and objectives established above, how the company compares to utility peers, and establish what the real and practical gap, need, risks and priorities are. This will ensure that fit for purpose and realistic iESP capabilities can be designed and deployed. Below is the quantification of PSE&G's standing in the industry as it applies to smart meter and device deployment using data from the United States Energy Information Administration (EIA). This information has been used as a basis for analyzing and prioritizing the iESP capabilities and designing the deployment program.

AMI penetration.[1]: as of the end of 2016,

- Advanced metering infrastructure (AMI) has been deployed to approximately 47% of utility customers (>70m meters) nationwide
- Four (4) states have **less than 1% Smart Device** penetration: **New Jersey,** West Virginia, New York, and Rhode Island
  - However, Con Edison (NY) has been approved to deploy Smart Devices by 2022
- New Jersey has less than 50,000 AMI meters (and no residential meters) deployed and is **47th in terms of Smart Device penetration in the US**
- Rockland Energy has been approved to deploy 75,000 meters by the end of 2019.

This will leave New Jersey, Rhode Island and West Virginia as the **last three states** that will not have a Smart Device deployment program

Figure 1-2: EIA Smart Device Penetration Statistics 2016



There is little doubt based on the industry data and experience that grid modernization is a key element of the transition to a smart utility, and critical to the foundations of both is the establishment of sophisticated, scalable and secure iESP capability. Without this capability PSE&G risks having an upper limit on its ability to transform its customer and utility operations to meet their smart utility aspirations.

1.4 REPORT OVERVIEW

This report presents the broad case for change for deploying PSE&G Energy Cloud-enabled business and technology capabilities that will form the foundation to support PSE&G's smart utility initiatives to continuously improve performance and help maintain and increase PSE&G's leading utility status.

[1] https://www.eia.gov/electricity/data/eia861/

Figure 1-3: PSE&G Energy Cloud Challenges, Response, and Deliverables

Challenge	Project Response & Deliverables
Technical capability – architecture must enable business use case roadmap and be scalable, secure, accessible, flexible and support real-time operations and future capabilities.	• Driven by business use case capabilities • Not a "one size fits all" architecture • Network and data services should be open and follow industry standards, and support the Energy Cloud vision • Scalability built into planning **IT/OT Architecture Overview and Impacts**
Deployment Roadmap and Plan must be comprehensive, practical, and achievable and drive early wins, momentum and value.	• Foundational iESP infrastructure deployed ~4 years • Use Capability deployed in 4 releases with a practical mix of foundational, advanced and future use case capabilities • Core governance (program, technology, data), change management and communications components included **PSE&G Energy Cloud Deployment Roadmap & Plan** **iESP Deployment & Management Organization**

The major components of this case for change include the business case, staffing plan, deployment roadmap and plan, and the technology architecture implications. The business case explores the costs and benefits of continuing the successful journey of deploying the foundational iESP and PSE&G Energy Cloud. The benefits of initiatives and capabilities that will be realized in the near-term of the 20-year horizon were determined using a series of use cases:

- Benefits for a total of 22 initiatives were measured using use cases and account for the benefits reported in the business case. These 22 use cases along with the foundational iESP deployment are considered release one (1) of the use case capabilities associated with the PSE&G Energy Cloud.
- An additional 48 initiatives and capabilities are anticipated to be supported by the PSE&G Energy Cloud but will require further development before they are ready for implementation. These initiatives are spread across (3) three additional releases noted in the deployment roadmap.

The conclusions included in the business case represent the culmination of a rigorous approach undertaken to identify and quantify potential smart utility opportunity benefits (i.e., cost savings, reliability performance improvement, productivity, efficiency, etc.), which will be explained throughout the body of the business case. Operational and certain societal and customer benefits are quantified, while other societal and customer benefits that cannot easily be quantified are discussed qualitatively. These benefits are identified and described qualitatively in sections 3.1 through 3.7 of this business case. In addition, in section 3.8 enhanced PSE&G Energy Cloud-enabled future capabilities are identified to recognize the expansion potential of initiatives as the needs of customers and PSE&G continue to evolve. The PSE&G Energy Cloud will allow the company to provide customers with a range of advanced analytic and other smart products and services. The future capabilities, in conjunction with advanced analytics and cost-effective, available technology, will allow PSE&G to make New Jersey a leading state in smart energy services and technology deployment.

To summarize the quantifiable benefits, which are detailed further in section 5.2, it is estimated that during the deployment and realization period of twenty (20) years, PSE&G can deliver:

- A net benefit of up to $937 million directly to customers, society and PSE&G;
- Up to an estimated 2% reduction in System Average Interruption Duration Index (SAIDI); and
- A potential 2,761 tonnage reduction in carbon emissions;

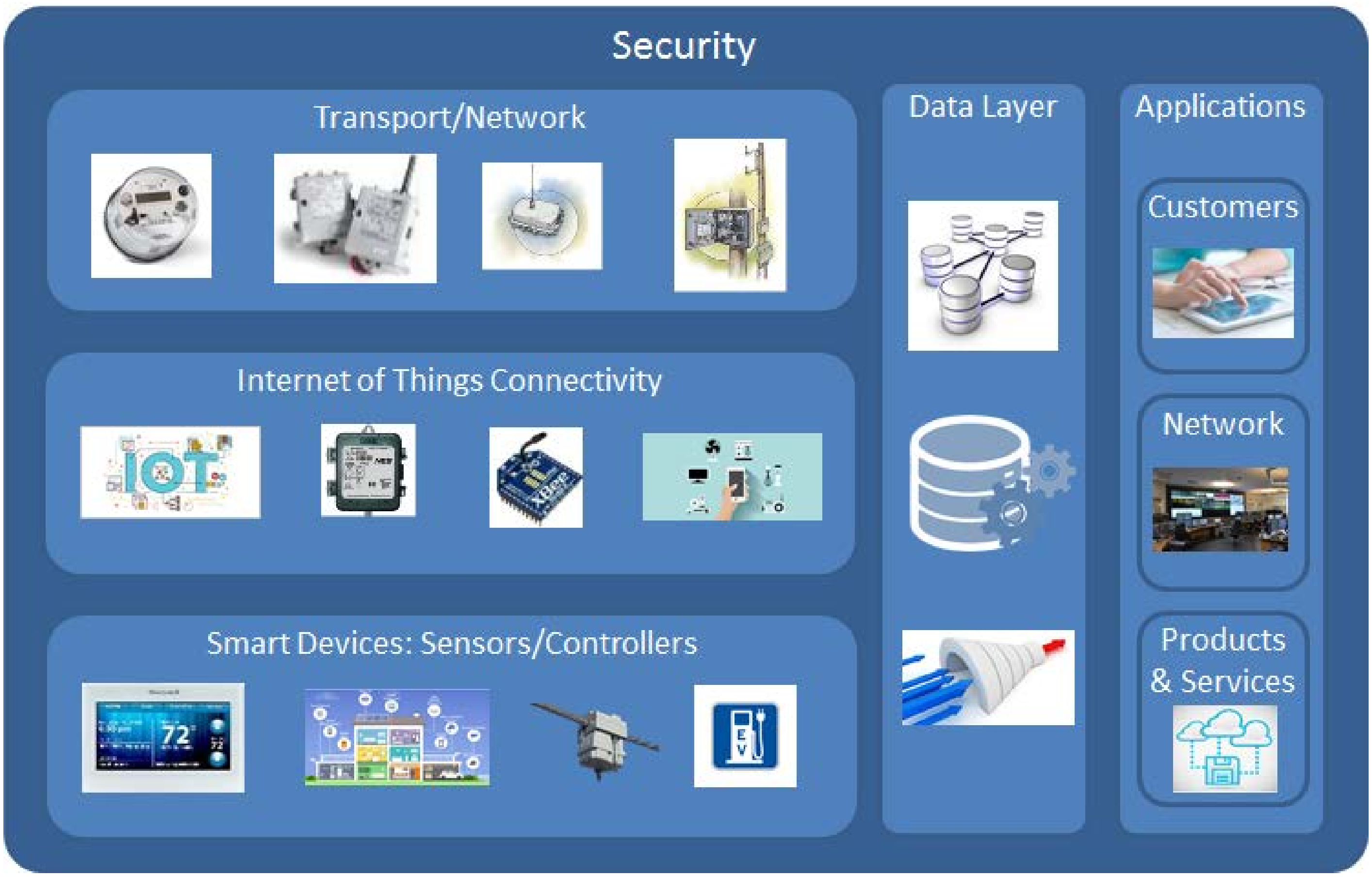
It is understood that some costs will be incurred to deploy the various cost-saving initiatives, and these costs are identified throughout this business case.

Through the deployment of the foundational iESP, certain staffing requirements will be impacted. PSE&G has developed a Staffing Plan (summarized in section 4.3) of the business case that identifies the impact that implementing the foundational iESP will have on the company's employees and the opportunities PSE&G plans to offer these employees to mitigate the impact. Additionally, a Customer Engagement Strategy has been developed to ensure that PSE&G engages and supports customers throughout the Energy Cloud deployment. This is a separate document included in the filing highlighting a number of customer communication efforts PSE&G will conduct with customers prior to and throughout the CEF-EC deployment. The Strategy identifies a number of messages, objectives, channels, and materials that will be used to facilitate customer engagement. The timing and nature of this engagement with customers are identified in order to, among other things, socialize the benefits of the PSE&G Energy Cloud implementation and address any customer issues associated with the PSE&G Energy Cloud implementation.

This business case also identifies, in sections 4.1 and 4.2 below, a deployment roadmap that lays out the implementation schedule of each of the 70 initiatives (use case) supported by the PSE&G Energy Cloud. The 22 initial initiatives for which the benefits were quantified as part of the business case that comprise release one will be implemented over the first five years of the PSE&G Energy Cloud deployment, while the remaining 48 initiatives will be implemented over a longer time horizon. The PSE&G Energy Cloud deployment aligns with other PSE&G regulatory filings, including Energy Strong and Clean Energy Future, as well as PSE&G's efforts to support energy efficiency, EVs, and smart grid.

This program will obviously rely heavily on technology infrastructure to enable the business and customer use cases on the roadmap. At its core will be the iESP which is comprised of the infrastructure on which the PSE&G Energy Cloud operates. As illustrated below, the iESP includes a two-way communications network, a layer to collect and analyze operational and customer data, an IoT platform, and an application runtime in which multiple services and applications are developed. The iESP will also include robust cyber security components to support information protection and operational continuity.

Figure 1-4: PSE&G Intelligent Energy Service Platform



1.5 BUSINESS CASE FINDINGS

The following provides a summary and some high-level details of the key PSE&G Energy Cloud business case elements, specifically operational benefits (O&M), customer benefits (customer, societal, environment), estimated costs[2] (capital and O&M) and net benefits.

The following figure shows the build-up of benefits along with the costs and net benefits for the deployment of the PSE&G Energy Cloud.

Figure 1-5: Cost-Benefit Analysis Overview

Business Case Overview $M		
Benefits	**Nominal Value**	**Present Value***
1. Operational Benefits	$887	$384
2. Customer Benefits	$843	$372
3. Total Benefits (1 + 2)	**$1,730**	**$756**
Costs		
4. O&M Costs	($73)	($56)
5. Capital Costs	($721)	($553)
6. Total Costs (4 + 5)	**($794)**	**($609)**
Net Benefits		
7. Net Benefit (3 – 6)	**$937**	**$147**

Figure 1-6: Benefits Overview (20-Year horizon)

Benefits Overview $M		
Operational Benefits	**Nominal Value**	**Present Value***
Customer Operations	$567	$245
Grid Operations - Gas	$196	$85
Grid Operations – Electric	$124	$54
Total Operational Benefits	**$887**	**$384**
Customer Benefits		
Time of use rates	$38	$16
Better storm outage response	$38	$17
Reduction in usage related to inactive accounts	$266	$118
Reduction in write-offs	$353	$153
Avoided energy theft	$138	$62
Recovered line loss due to slow meters	$11	$5
Future Capabilities	Individual Cases	
Total Customer Benefits	**$843**	**$372**
Total Benefits	**$1,730**	**$756**

* Present value is based on pre-tax cash flows at 6.85% discount rate per PSE&G's 12+0 rate case filing

As can be seen above in figure 1-5, the net effect of the benefits and costs coming from a broader range of Energy Cloud use cases is a business case that is economically viable, with net benefits of $937m. Details regarding the assumptions and calculations underlying these costs and benefits are set forth in section 5.2 of this business case.

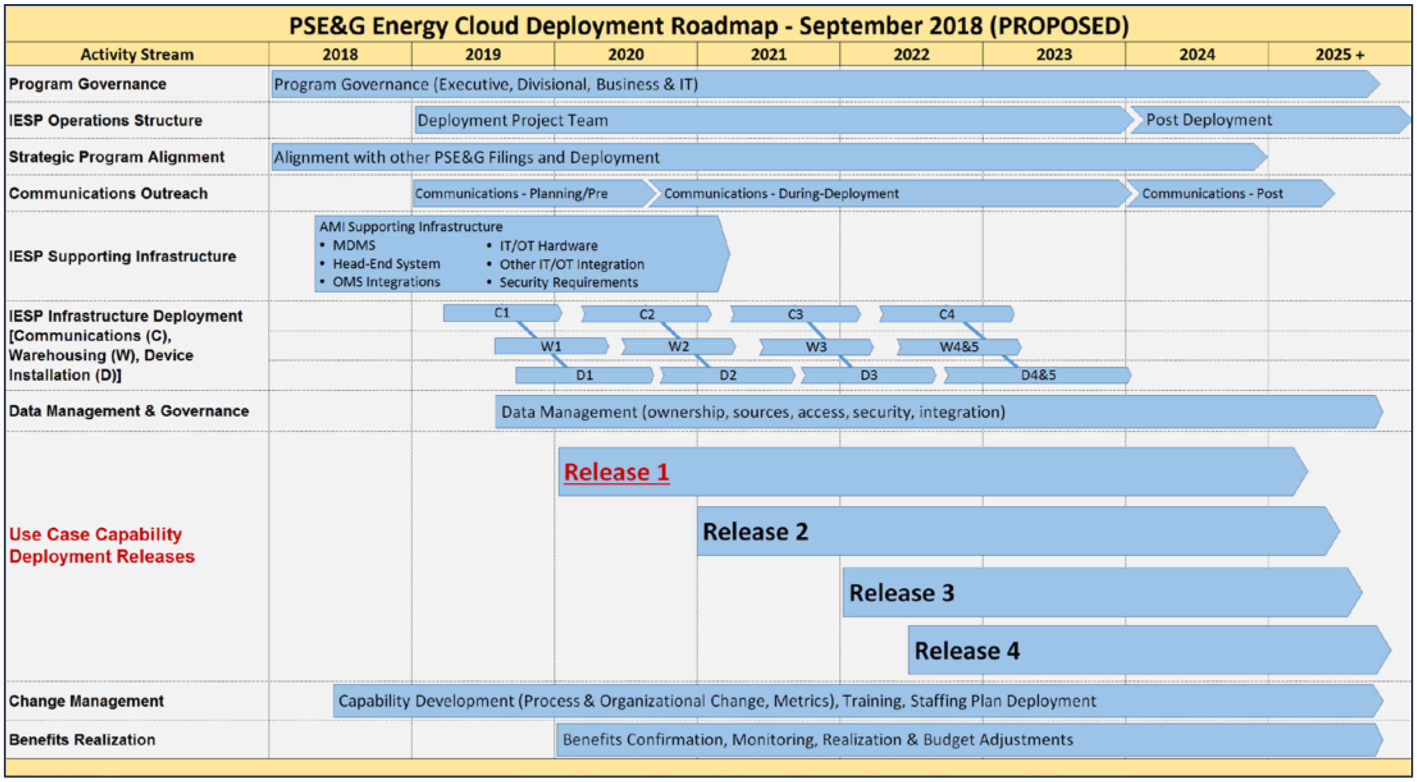
[2] THESE ARE THE FULLY LOADED DEVICE INSTALLATION COSTS THAT INCLUDE THE COST OF LABOR FOR DEVICE INSTALLERS AND SUPPORT PERSONNEL (I.E., PROJECT MANAGEMENT, WAREHOUSE MANAGEMENT AND SUPPORT, SUPERVISOR AND QUALITY ASSURANCE, AND CALL CENTER MANAGEMENT AND STAFF), VEHICLES AND FUEL, TOOLS, MOBILE TECHNOLOGY, WORK ORDER MANAGEMENT SYSTEM, AND EMPLOYEE RECRUITMENT AND TRAINING.

1.6 PSE&G ENERGY CLOUD CAPABILITY DEPLOYMENT PROGRAM ROADMAP

Based on the identification, analysis and prioritization of the utility of the future capabilities (use cases) the following overall PSE&G Energy Cloud program roadmap was developed. This deployment roadmap is structured around 70 PSE&G applicable use cases organized into four capability release groups based on value, complexity and type (foundational, advanced or future), and the planned five-year roll-out of iESP devices and communications.

Note also that to ensure early realization of benefits and to build momentum for the program, 22 (fundamental and advanced) of these 70 use cases were prioritized to be deployed in release 1 alongside this initial iESP devices and communications implementation.

Figure 1-7: PSE&G Energy Cloud Deployment Roadmap

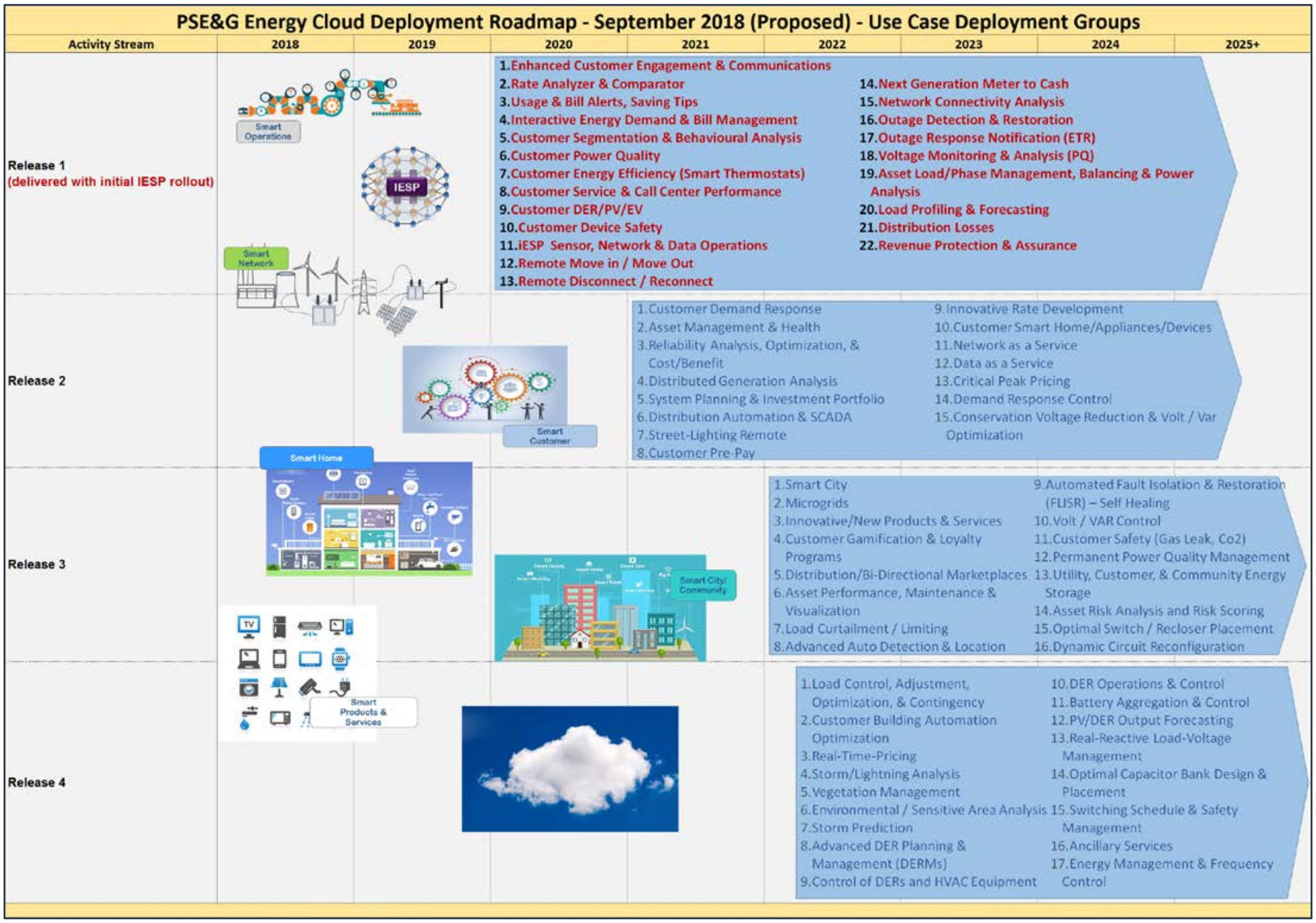


The figures below lists the 70 PSE&G applicable uses cases on the Energy Cloud Roadmap, their planned roadmap deployment group (releases) and their type - foundational, advanced or future enabled – with the types defined as follows:

1. Foundational/Upgrade – use cases that can be fully deployed and enabled with none or minor additional iESP capability upgrades and are key dependencies for “advanced” or “future enabled” use cases.
2. Advanced – use cases that can be fully deployed and enabled with additional and advanced iESP capabilities (sensors, control boards, street lighting, data streams, etc.) and are key dependencies for “future enabled” use cases.
3. Future Enabled – use cases that can be supported partially by iESP (data, network), but require additional and external capabilities (SAP, CRM, Smart City, additional rate approval, internet, advanced analytics) to fully realize potential.

Note: The 22 priority use cases chosen for inclusion in the initial CEF-EC Release 1 deployment are **highlighted in red,** with the complete list of 70 in figure 1-8 below.

Figure 1-8: PSE&G Energy Cloud Use Case Deployment Group Schedule



As stated CEF-EC Release 1 deployment consists of 22 smart capabilities (use cases) that will, alongside the iESP infrastructure, system, and data services deployment, enable a number of smart capabilities which in turn will deliver a number of customer and operational benefits.

With respect to customer benefits: use case capabilities planned in Release 1 will focus on enhanced engagement and service, automated alerts and tips, support for energy efficiency and DER needs, and a range of advanced self-service energy and billing capabilities. Other customer-focused capabilities include the availability of additional usage and service data that will enable customers to reduce their bills by matching their profile to a better rate or joining energy efficiency initiatives. Meter alerts can warn customers and PSE&G if there are issues, particularly safety related, with their connections. For example, it was reported in early September 2018 that a smart meter Con Edison installed in a New York residence alerted the utility to an unsafe condition behind the meter, possibly preventing a house fire.3 The ability to communicate in real time with the meter will also deliver a number of outage and power quality benefits. These capabilities and additional data should result in increased customer service and satisfaction.

With respect to operational benefits: Release 1 capabilities will focus on leveraging additional and more accurate data and infrastructure to enable new capabilities, including automated and on-demand meter reading, remote disconnect and reconnect services, automated move-in and move-out work, active voltage and load management, outage detection and response, and energy theft protection. These capabilities are expected to deliver significant operational benefits for meter reading, avoided work (truck rolls and service appointments), improved outage response, reduced bad debt and write-offs, improved meter to cash efficiencies, and reduced energy theft.

[3] https://newyork.cbslocal.com/2018/09/06/con-edison-smart-meter-new-rochelle/

Figure 1-9: PSE&G Energy Cloud Use Case Deployment Groups

PSE&G Applicable Use Case Capabilities (70) – On the Roadmap

Release 1 – with iESP (22)

1. Enhanced Customer Engagement & Communications
2. Rate Analyzer & Comparator
3. Usage & Bill Alerts, Saving Tips
4. Interactive Energy Demand & Bill Management
5. Customer Segmentation & Behavioural Analysis
6. Customer Power Quality
7. Customer Energy Efficiency (Smart Thermostats)
8. Customer Service & Call Center Performance
9. Customer DER/PV/EV
10. Customer Device Safety
11. iESP Sensor, Network & Data Operations
12. Remote Move in / Move Out
13. Remote Disconnect / Reconnect
14. Next Generation Meter to Cash
15. Network Connectivity Analysis
16. Outage Detection & Restoration
17. Outage Response Notification (ETR)
18. Voltage Monitoring & Analysis
19. Asset Load/Phase Management, Balancing & Power Analysis
20. Load Profiling & Forecasting
21. Distribution Losses
22. Revenue Protection & Assurance

Release 2 (15)

1. Customer Demand Response
2. Asset Management & Health
3. Reliability Analysis, Optimization, & Cost/Benefit
4. Distributed Generation Analysis
5. System Planning & Investment Portfolio
6. Distribution Automation & SCADA
7. Street-Lighting Remote
8. Customer Pre-Pay
9. Innovative Rate Development
10. Customer Smart Home/Appliances/Devices
11. Network as a Service
12. Data as a Service
13. Critical Peak Pricing
14. Demand Response Control
15. Conservation Voltage Reduction

Release 3 (16)

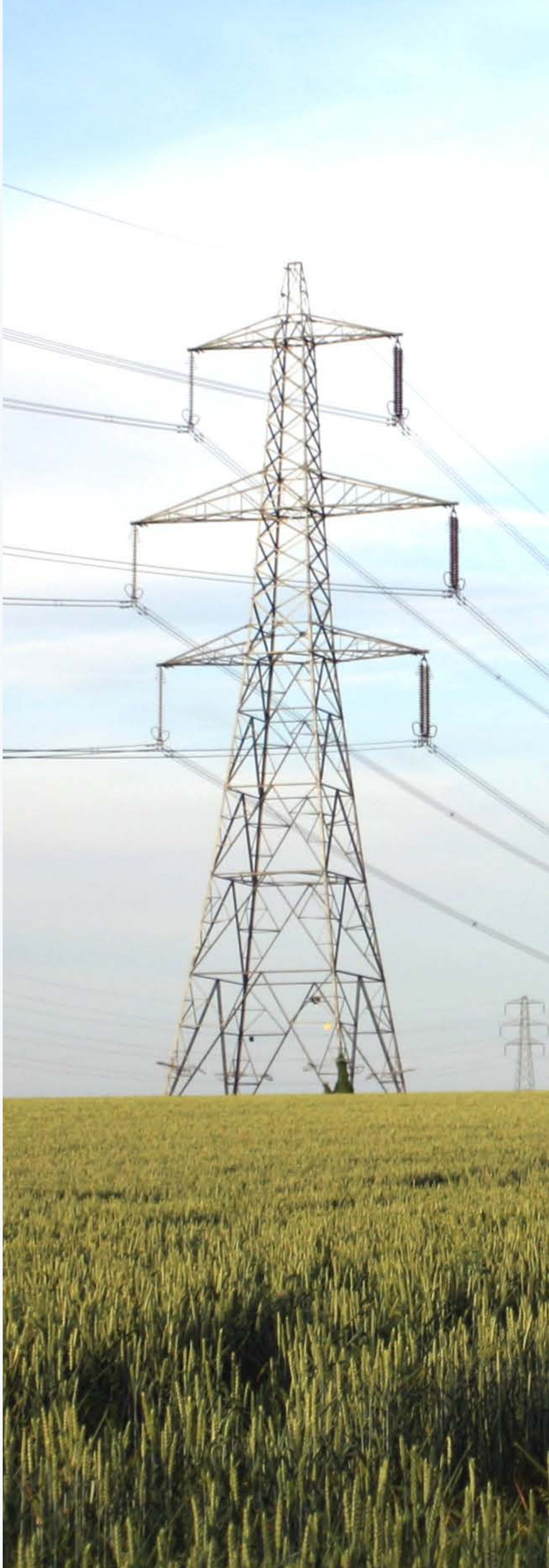
1. Smart City
2. Microgrids
3. Innovative/New Products & Services
4. Customer Gamification & Loyalty Programs
5. Distribution/Bi-Directional Marketplaces
6. Asset Performance, Maintenance & Visualization
7. Load Curtailment / Limiting
8. Advanced Auto Detection & Location
9. Automated Fault Isolation & Restoration (FLISR) – Self Healing
10. Volt / VAR Optimization & Control (VVO/VVC)
11. Customer Safety (Gas Leak, Co2)
12. Permanent Power Quality Management
13. Utility, Customer, & Community Energy Storage
14. Asset Risk Analysis and Risk Scoring
15. Optimal Switch / Recloser Placement
16. Dynamic Circuit Reconfiguration

Release 4 (17)

1. Load Control, Adjustment, Optimization, & Contingency
2. Customer Building Automation Optimization
3. Real-Time-Pricing
4. Storm/Lightning Analysis
5. Vegetation Management
6. Environmental / Sensitive Area Analysis
7. Storm Prediction
8. Advanced DER Planning & Management (DERMs)
9. Control of DERs and HVAC Equipment
10. DER Operations & Control
11. Battery Aggregation & Control
12. PV/DER Output Forecasting
13. Real-Reactive Load-Voltage Management
14. Optimal Capacitor Bank Design & Placement
15. Switching Schedule & Safety Management
16. Ancillary Services
17. Energy Management & Frequency Control

02

GENERAL CONSIDERATIONS



2 GENERAL CONSIDERATIONS

PSE&G is pursuing a program with the intent of evolving into a 'smart utility' that is capable of promoting a smart energy future for New Jersey. This will be achieved through the enablement of connected smart customer, smart utility, smart home and smart city capabilities deployed on a foundational intelligent energy services platform – the PSE&G Energy Cloud. This platform, which will be inclusive of all customers, will provide infrastructure and data services that can be leveraged and integrated with IoT platforms and data to enable a whole new future of customer engagement and utility operations.

The benefits associated with this vision far outweigh the costs and are derived by quantifying the impacts of 22 initial use cases that are supported by the iESP that forms the foundation upon which the Energy Cloud will gain its functionality. To calculate the quantitative benefits, this business case identifies various use cases that are applicable to the reduction of redundant or unnecessary processes that will no longer be required once the PSE&G Energy Cloud is deployed. Examples of the quantitative benefits captured in the business case include cost savings, productivity enhancements, efficiency improvements, reduced outage durations, and carbon emission reductions, among others. The applicable use cases, their descriptions, and calculations are included in the sections that follow, specifically section 5.2. There are also qualitative benefits associated with the use cases that are identified in this business case. These include opportunities to enhance customer satisfaction levels and increase the capability for future changes to the grid. The benefits are qualified as examples, including: customer satisfaction, enhanced capability, resiliency, emergency preparedness, environmental gains, and others. See Section 3 for further description of qualitative benefits.

2.1 PSE&G ENERGY CLOUD OBJECTIVES

The following objectives underlie the PSE&G Energy Cloud and provide direction for its design and deployment as established in this business case:

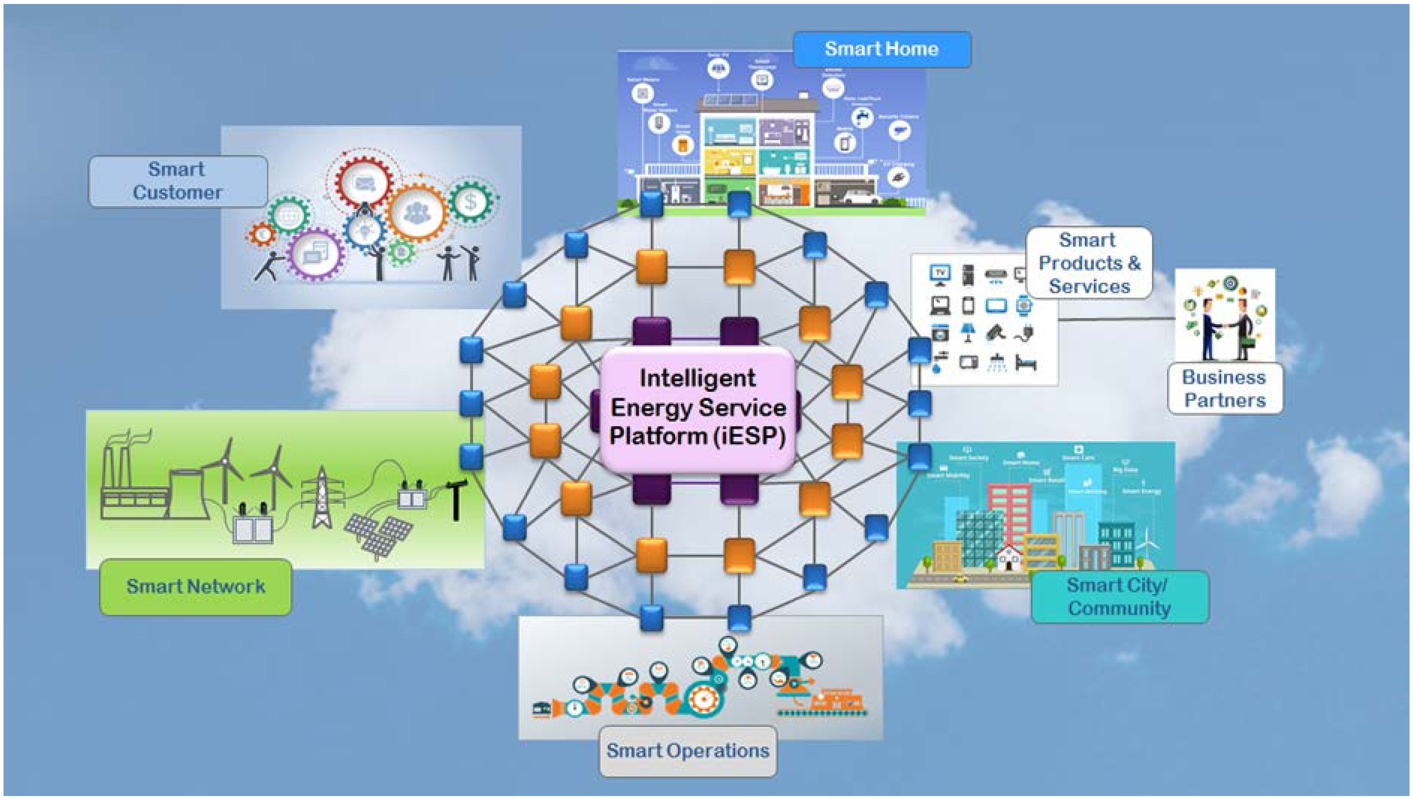
- The customer is at the core of all energy cloud capability development.
  - Deliver improved customer service by energy suppliers, including easier switching and price transparency, accurate bills and new tariff and payment options.
  - Deliver customer support for the deployment based on recognition of the consumer benefits, and confidence in the arrangements for data protection, access, safety, and use.
  - Promote cost-effective and environmentally beneficial energy savings, enabling all consumers to better manage their energy consumption and expenditure and experience carbon savings.
- The focus should be on smart utility capability development (e.g., people, process, and governance) rather being simply technology- and data-based to ensure successful business adoption.
  - Enable simplification of industry processes and resulting cost savings and service improvements.
- Ensure the PSE&G Energy Cloud design considers and establishes the foundational components required to enable future smart utility capabilities over a 10-20 year horizon.
  - Facilitate anticipated changes in the electricity supply sector and reduce the costs of delivering (generating and distributing) energy.
  - Promote effective competition in all relevant markets (energy supply, metering provision, energy services and home automation).
  - Ensure that timely information and suitable functionality is provided through smart devices and the associated communications architecture, where cost effective, to support development of smart grids.
  - Ensure that the dependencies on smart infrastructure of wider areas of potential public policy initiatives are identified and included within the strategic business case, where they are justified in cost-benefit terms.
- Align and plan smart utility capability deployment with corporate goals and initiatives around ADMS, VVO, digitization, renewables, enhanced products and services, and customer engagement.
- Ensure that the business units drive and lead, with IT partnership and enablement to ensure the business impact of technology is always considered and factored into deployment.
  - Deliver the necessary design requirements, commercial and regulatory framework and supporting activities so as to achieve the timely development and cost-effective implementation of the PSE&G Energy Cloud.
- Adopt a program-level value-based approach to smart utility strategy and roadmap governance.
- Deploy use case capability in a managed (POC -> Pilot -> Production) Agile manner according to the program roadmap.
- Ensure that the smart utility capabilities enable operational and customer innovation yet still retain integrity and solid performance around core business needs.

  - Ensure that the communications infrastructure, devices and data management arrangements meet specified requirements for security and resilience and command the confidence of stakeholders.

- Incorporate formal data quality and governance processes into overall program governance.
- Adopt an optimized "best of breed" approach to use case solution selection and deployment.
- Leverage current technology and data capabilities where possible.
- Manage the transition to a new operating analytics capability using collaborative change management, and effective and timely communications.

The PSE&G Energy Cloud and its foundational iESP will support six key capabilities that will support the company's evolution towards a next generation utility and New Jersey's smart state IoT-enabled future: smart operations, smart network, smart customer, smart home, smart products and services, and smart city / community.

Figure 2-1: PSE&G Energy Cloud Key Capabilities



2.2 APPROACH AND ASSUMPTIONS

2.2.1 Use Case Approach

Deployment of the PSE&G Energy Cloud and its foundational iESP provides a number of operational benefits, examples of which are found in the areas of remote disconnect-reconnect, revenue assurance, and device maintenance, among many others. These operational benefits were quantified in this business case using a 'use case' methodology after thorough examination of each potential benefit area to identify the appropriate cost savings of implementing the PSE&G Energy Cloud.

The first step of the use case methodology was to complete an examination of current use case applications as well as data availability and quality across the organization. This was followed by a scan across various use case domains, including customer, grid, reliability, etc., to assess the existing capability and determine which use cases would be most applicable to deployment of the PSE&G Energy Cloud. A comprehensive repository of industry use cases was analyzed resulting in a final list as shown in Figure 2.2.

Figure 2-2: Comprehensive Use Case Repository

PSE&G Use Case Repository

Asset / Operations / Reliability / Load	Customer	DER / Voltage / Grid/Outage
Asset	**Customer**	**DER**
Asset Management & Maintenance	Behavioral Analysis	Advanced Distribution Automation (DER included)
Asset Performance / Health & Visualization	Critical Peak Pricing	Distributed Generation Analysis
Network Connectivity Analysis	Customer Portal & Self Service	DER Controller
Failure Notice	Customer Communications	DER Forecasting
Budgetary Planning	Customer Demand Response	Utility, Customer, & Community Energy Storage
Maintenance Optimization	Customer Photovoltaics (PV) Generation Source	Control of DERs and HVAC Equipment
Risk Analysis and Risk Scoring	Customer Reliability & Safety	Energy Management by Configuring a Virtual Microgrid
Asset Compliance	Customer Research, Segmentation, Targeting, marketing & Messaging	Online Power System Control by Battery Aggregation
Dynamic Asset Rating	Customer Service & Call Center Performance	Peak Shift Contribution by Battery Aggregation
Operations	Demand Response Planning & Management	PV Output Forecasting/ Backcasting
Demand Response Control	Distributed Energy Resource (DER) Asset Performance	DER Operations & Control & Integrated DER Management
Distribution Automation & Supervisory Control and Data Acquisition (SCADA)	Device Provisioning	**Voltage**
Distribution Grid Management	Energy Efficiency	Conservation Voltage Reduction
Field Control Request	Smart House Analysis & Management	Optimal Capacitor Bank Design & Placement
Load Shedding	Gamification/Loyalty Programs	Permanent Power Quality Measurement
Managing System Stability	Load Disaggregation	Volt / VAR Control
Protection	Loyalty Programs	Volt / VAR Optimization
State Estimation	Device to Cash	Voltage Control, Regulation & Security
Switching Schedule & Safety Management	Online Bill Presentment	Voltage Monitoring & Analysis (PQ)
Real-Reactive Load-Voltage Management	Plug-In Electric Vehicles	**Grid/Outage**
Reliability	Rate Analyzer & Comparator	Advanced Auto Restoration & Self-Healing Grid
Reliability Analysis, Optimization, & Cost / Benefit	Real-Time-Pricing	Fault Detection, Location, Isolation & Response (FLISR)
Optimal Switch / Recloser Placement	Revenue Protection & Assurance	Storm Prediction
Storm Analysis	Upsell/Cross-Sell/bundle Products & Services	Outage Detection & Notification
Vegetation Management	Usage & Bill Alerts, Saving Tips, Monitor & Compare	Outage Restoration Notification
Load	Pricing & event Customer Opt-Out	Distribution Outage Schedules
Asset Load & Power Analysis		
Technical Losses		
Load Control, Adjustment, Optimization, & Contingency		
Load Forecasting, Profiling, Shedding, & Balancing		
Low Side Rollover Specifications		

A total of 70 use cases were identified for inclusion in the PSE&G Energy Cloud and were broken out by their level of sophistication and assigned to one of four release tranches based on the ease of deployment and maturity of the business unit capabilities supporting the opportunity.

The use cases identified for release one are all foundational / upgrades that are supported with few, if any, upgrades beyond the iESP deployment. The use cases included in releases two and three are predominantly advanced, while the use cases included in release four typically require additional external capabilities and are classified as future-enabled.

After the initial identification of applicable use cases, this business case sets forth identified quantitative and qualitative benefits of deploying iESP in PSE&G's territory. This business case will also discuss societal and customer benefits, as well as financial savings.

Lastly, this business case includes a prioritized roadmap developed to leverage the value of deploying the PSE&G Energy Cloud and iESP infrastructure utilizing a rigorous method for assessing, prioritizing, and effectively managing the deployment and benefits realization.

2.2.2 Use Case Assumptions

During the development of this business case, PSE&G internal resources were used to thoroughly analyze and ensure that benefits were not double-counted or tacked on top of previously sought out benefits. The benefits identified in this business case are completely independent of all external regulatory filings and internal PSE&G initiatives that might overlap use case benefits.

2.2.3 Additional Considerations

As the distribution utility landscape changes as part of the PSE&G Energy Cloud deployment, certain employment positions will no longer be required. A summary of the Staffing Plan is included as part of this business case in section 4.3 to ensure redeployment opportunities are provided to all permanent employees, and that PSE&G offers retraining and development programs to ensure all impacted employees are effectively redeployed.

Lastly, as is summarized in Figure 2-3 below, this business case was developed with consideration of all customers and it identifies specific initiatives to encourage the participation and support for smart device deployment by all stakeholders.

Figure 2-3: Customer Considerations & Initiatives

<table>
<tr><th colspan="2">PSE&G Customer Considerations</th></tr>
<tr><td>Rate Design Options</td><td>Implementing smart devices allows PSE&G to design future customer-focused, tailored rate design options to increase customer satisfaction</td></tr>
<tr><td>Opt-Out Option</td><td>Providing opt-out options is an integral part of deploying smart devices across a jurisdiction to increase customer retention and buy-in for iESP deployment. Opt-out options available to PSE&G residential customers will be as follows:
Eligibility
Residential customers who are not comfortable with the technology or have other concerns following the Company's education and outreach efforts will be eligible to opt-out of receiving an AMI meter. Commercial and industrial customers will not be subject to opting out of AMI.
Cost
<u>Meter Replacements</u>
Customers who opt-out of an AMI meter will receive a solid state, digital, non-radio frequency emitting meter that will be manually read. Customers will be charged a one-time charge of $45.00 for the replacement of an AMI meter with the aforementioned non-radio frequency emitting meter.
<u>Monthly Meter Reading</u>
Customers who choose to opt-out of receiving AMI meters will incur a $20 monthly meter reading cost per account.
<u>Responsibility</u>
PSE&G will notify customers in writing that AMI meters are to be installed at least 45 days in advance of the AMI meter installation. This communication will provide details about the opt-out process and notify customers that opt-out requests should made within 15 days of receipt of the notification. It will also include the opt-out and replacement fees discussed above. The objective is to minimize instances where customers receive AMI meters prior to them notifying the Company of their intent to opt-out.</td></tr>
<tr><td>Targeted Marketing / Communication Efforts</td><td>Smart devices, and the associated analytics, allow PSE&G to provide its customers with target marketing communications that highlight the energy usage of similar, anonymous customers and ways to reduce energy usage</td></tr>
<tr><td>Future Capabilities</td><td>iESP provides the utility with the ability to enhance the current grid and customer capabilities, as well as prepare for further future grid modernization efforts</td></tr>
</table>

03

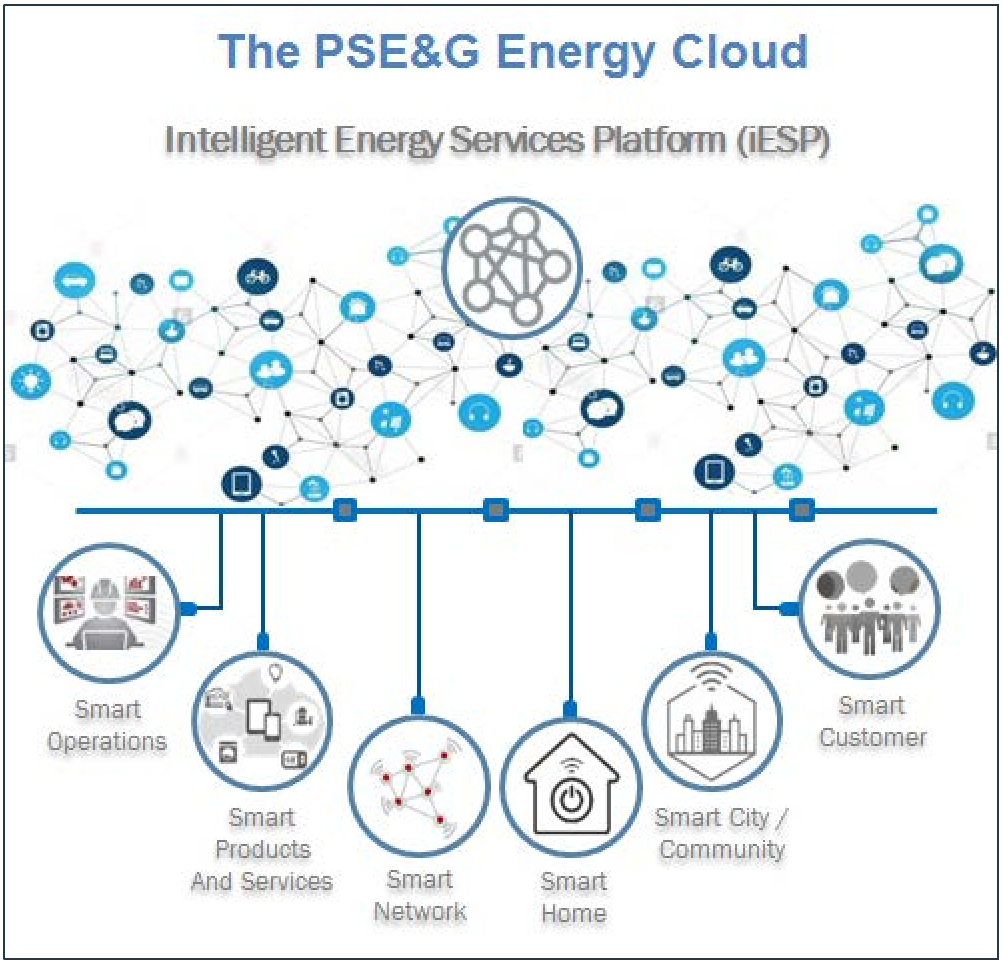
THE CASE FOR THE PSE&G ENERGY CLOUD

3 THE CASE FOR THE PSE&G ENERGY CLOUD

The next generation utility will need to operate and compete in non-traditional ways that focus on offering new energy products and services that use operational and customer data and digital platforms to customize offerings, improve service, and empower consumers. A number of global and local trends are driving this need to adapt, and utilities need to build business capability and platforms that will enable them to operate under this new paradigm.

The vision to develop the PSE&G Energy Cloud platform and its six capabilities will enable and evolve over time a range of expanded and enhanced energy products, services and capabilities that will deliver societal and economic value for all of PSE&G's stakeholders, including customers, communities, and cities.

Figure 3-1: PSE&G Energy Cloud Components



Benefits for a total of 22 initiatives were measured using use cases and account for the benefits reported in this business case. These 22 initiatives along with the foundational iESP deployment are considered release one (1) of the use case capabilities associated with the PSE&G Energy Cloud.

3.1 INTELLIGENT ENERGY SERVICE PLATFORM

The iESP is comprised of the infrastructure on which the PSE&G Energy Cloud operates. It will consist of and/or support:

- Smart devices (sensors, meters, and controllers) that enable the collection of network and customer energy data to enable smart capabilities;
- Optimized, scalable, accessible and secure communications network of bridges and gateways based on standard protocols;
- Comprehensive device management command center capability scalable to the management of multiple types of end-point devices;

- Best practice data exchange governance and management capability through an advanced application programming interface platform;
- Advanced data analytics, artificial intelligence, augmented reality, voice computing, and other application development capabilities; and
- A development platform where participants develop and competitively market solutions to PSE&G customers. As an example, a home automation company could offer security services leveraging the PSE&G Energy Cloud network.

Note that the Release 1 iESP implementation will include the extension of the current ECNet RF Mesh Network, currently deployed for commercial and industrial customers, across the remaining PSE&G service territory including:

- 182 additional data collectors/gateways (ECNet – currently 26 deployed)
- 2,370 routers/bridges (ECNet – currently 2,300 deployed)
- 2.2 million smart electric meters (ECNet – currently 15,000 deployed for commercial and industrial customers).

3.2 NEXT GENERATION UTILITY AND SMART OPERATIONS

The PSE&G Energy Cloud will support a reliable and customer-centric utility where automated operations, tailored and predictive customer experience, and service flexibility are the norm.

Smart energy operations will enable:

- Enhanced customer service through the provision of detailed smart device data to call center representatives and other customer agents that facilitates a 360 degree view of the customer;
- Automated remote operation of smart meters at customer premises (e.g. almost instantaneous response to customer move in, move out requests);
- Lower operating costs resulting from a high degree of automation at all levels of the distribution system and meter-to-cash process like remote shutoff and reconnects, theft and loss detection;
- A high degree of automation at all levels of the distribution system, including, for example, artificial intelligence-based substation inspections, resulting in improved reliability and lower costs;
- Enhanced usage data, billing and customer service data accuracy resulting in higher customer satisfaction, reduced calls and significantly fewer exceptions to handle; and
- Earlier and pro-active detection, and more accurate information and customer notifications during outages along with the ability to receive real-time restoration information that will improve our restoration efforts.

An overview of select smart operations benefits that will be realized beginning with release one of the capabilities enabled by the PSE&G Energy Cloud are included below. A full accounting of smart operations initiatives and capabilities enabled by release one and subsequent releases are identified in chapter 4 of this report.

Multi-Family Disconnect

With multi-family units, access to devices can be limited and requires the assistance and permission of the resident and/or landlord, often requiring paying customers to be inconvenienced in order to disconnect those who are not paying. The process to manually disconnect a device that is inaccessible requires a different process than that used to disconnect a typically-accessible device, including a truck roll associated with the reconnect or disconnect. Smart devices provide a remote ability to reconnect and disconnect devices that are inaccessible, and, therefore eliminates the need for truck rolls and potential customer inconvenience

Customer Service & Call Center Performance

Smart devices and the accuracy in read rate and data quality provided by them will likely reduce the volume of calls from customers to PSE&G call centers, as 20% of current customer calls relate to billing inaccuracies (including estimated bills), billing challenges, and similar issues. With the additional information provided by iESP devices, these calls would likely be eliminated. A key goal is the use of a broader range of information (including iESP) to expand products, bolster service, improve customer satisfaction, and lower costs by bringing together historical and real-time information to support customer service representatives' decision analysis and improve the customer experience and service fulfillment.

Remote Device Operations / Rate Change Orders

Currently, PSE&G conducts around 5,200 truck rolls in order to change devices when a customer moves to a different rate order. The limitation here is that different types of electromechanical devices are needed in order to facilitate billing of different rate orders. With iESP, the typical device would be able to collect various types of electric data, such as kWh, kW, bi-directional data, etc. Further, the devices will have the ability to receive software updates over the air

(OTA), which will enable PSE&G to push software changes to the device and collect different types of information required by the different rate structures. Hence, PSE&G would not have to conduct truck rolls to change out these devices. The PSE&G Energy Cloud provides the ability to obtain an “on-demand” reading of consumption, which will enable PSE&G to obtain a final device reading without dispatching dedicated personnel to do so. In addition, iESP would allow PSE&G to remotely disconnect or reconnect customers. This would allow PSE&G to avoid 265,797 truck rolls related to device reading and remote disconnect / reconnect.

Reduction in Cost Related to Consumption on Inactive Meters

The PSE&G Energy Cloud and the more detailed consumption data it provides allows for more accurate tracking of consumption. The ability to remotely disconnect inactive devices will reduce the annual consumption on inactive devices, which should lead to a decrease in the amount written off due to consumption on inactive meters. This in turn will reduce the amount of losses across the entire PSE&G customer base.

Inaccurate Device Reads

Smart devices can reduce device inaccuracies in two ways. First, the smart devices are all solid state electronic devices, which are more accurate than mechanical devices, which have a tendency to slow down over time. Use of smart devices will allow PSE&G to obtain much more accurate consumption data, and lead to a decline in billing challenges and disputes due to device inaccuracies. Second, the automated data updates provided by smart devices will reduce the amount of estimated bills sent to customers. This should help reduce the true-ups needed on subsequent bills to correct estimated consumption charges to actual consumption amounts. Customers will benefit from more reliable and accurate billing rates, and calls relating to questions surrounding trued-up charges will be reduced.

Reduction of Bad Debt / Theft / Losses

Revenue protection refers to the prevention, detection, and recovery of losses caused by interference with or theft of electricity. This use case leverages smart device consumption, voltage, and event data (e.g. device tilt flags) to detect energy theft and device tampering by employing multiple screening techniques including cross-service correlations. In addition, analysis considers the integration of revenue protection (e.g. theft) with other utility activities which impact the device-to-cash process more broadly such as malfunctioning devices and equipment. Smart devices and the timely consumption data and event flags they provide, in conjunction with the ability to remotely disconnect devices should help PSE&G reduce the losses from theft through faster identification, and consequentially reduce bad debt (consumption on inactive devices, consumption theft, and/or consumption from uncollectable accounts)

Enhanced Revenue Collection

The consumption data together with the disconnect capability should also help PSE&G collections to better enforce current collection processes and should reduce the overall socialized uncollectable portion of rates. Instead of coordinating with multiple external agencies to gain access to a device to perform a physical disconnect, which can be a lengthy process, the remote disconnect capability should allow PSE&G to minimize the consumption on devices that should have been disconnected from service for non-payment status.

Analytics

Utility analytics unlocks the value of iESP data by coordinating various forms of information across organizational departments, applications, and databases. Across the industry, utilities are leveraging iESP data in analytical solutions to deliver real business and customer benefits above those delivered by iESP deployment alone. These range from lower operations and maintenance costs, improved asset and load management, reduced outage frequency and improved service to and engagement with their customers. There are examples of utilities recovering half the costs of their smart grid programs by detecting and preventing energy theft alone. Other companies are reporting improvements in service reliability of over 35%, enabled in part by the deployment of sophisticated analytical capabilities using iESP data. Analytics can also be used to help meet sustainability goals and integrate renewables.

3.3 NEXT GENERATION UTILITY AND SMART NETWORK

The PSE&G Energy Cloud will enable continued operational excellence in a less predictable and more complex electric distribution network. As the capabilities and configuration of the distribution network transform to facilitate the widespread integration of DERs, EVs, and storage resources, to name a few, the PSE&G Energy Cloud will provide the data and processing platform required to maintain the reliability of services that customers are accustomed to today.

The smart energy network will enable:

- Identification and management of the high degree of network variability driven by solar, wind, battery storage, and EV use and storage, and maintain high level of reliability that customers expect that, when combined with knowledge of customer behavior, enables PSE&G to leverage large amounts of customer DER to offset peak demand;
- Advanced energy efficiency, critical peak pricing, demand response and demand control capabilities through the deployment of controllable smart devices;
- Management of PSE&G's network load and quality issues through the deployment of distributed intelligence devices (smart line/asset sensors, reclosers, capacitor banks, etc.) to improve efficiency and reduce energy and carbon emissions;
- Fully digitized asset registries and geo-coding that result in efficiency and safety gains like utilizing augmented reality to locate assets and perform inspections and 'mark-outs', and vehicle, satellite or drone based images (infrared, thermal, light detection and ranging (LIDAR), etc.) that when coupled with machine learning are used to optimize vegetation management and storm damage assessment;
- Monitoring and optimization of network load and voltage that will reduce asset overloading, identify and prevent potential areas of failure, solve power quality issues, reduce technical losses and enable CVR; and
- Advanced operations and distribution automation including automatic feeder sectionalizing and restoration with intelligent switches, voltage regulator monitoring and control through smart sensors and controllers.

An overview of select smart network benefits that will be realized beginning with release one of the capabilities enabled by the PSE&G Energy Cloud are included below. A full accounting of smart network initiatives and capabilities enabled by release one and subsequent releases are identified in chapter 4 of this report.

Reliability and Storm Outage Response

The PSE&G Energy Cloud deployment will allow PSE&G to have much greater visibility of the distribution system. District operators will have the ability to "see" the operational status of the network down to the customer meter level, which gives a much fuller picture of how the distribution system is performing. This increased level of operational visibility will allow PSE&G to make more informed decisions, which will lead to better reliability and customer service. Reliability improvements from the deployment of iESP will likely come from the faster identification of "nested outages" (secondary and service outages that are not identified or fixed during initial restoration activities, which are focused on primary distribution circuits). This can potentially shorten the overall system minutes of interruptions (and the associated System Average Interruption Duration Index, SAIDI), as well as shorten the tail end of major storm event restoration activities.

There are instances during outage restoration activities where there is significant damage on secondary services that do not become apparent until after the primary distribution circuit is restored. In these cases, the "nested" outages on the secondary side will not be identified until well after the restoration crews have departed and moved on to the next restoration area. Without iESP, the method to locate these "nested" outages is to depend on further customer restoration calls, and adds significant delays in completing the restoration of the affected area. For example, it took PSE&G an extra 1 to 2 days to address approximately 16,000 service and secondary outages during the October 2011 snowstorm. If iESP had been in place with the ability to ping devices and directly verify that an area has been restored, these restoration delays would have been avoided.

The increased visibility down to the device level will allow PSE&G district operators to determine exactly which devices are still out. By using other network and neighborhood information, PSE&G will be able to determine what restoration activities are needed to be performed in an area before troubleshooters and crews move to the next area. This faster identification of "nested" outages can significantly shorten the restoration activities, and potentially eliminate restoration crews visiting the same area multiple times. This improved system awareness of where outages are allowing for more efficient restoration activities which, in turn, shorten the "tail" of major event responses. This decreases the system outage durations for customers, allows PSE&G to go back to "normal" operations mode faster, and potentially allows for the release of mutual assistance crews earlier. Up to one minute of system SAIDI can potentially be eliminated with the elimination of these nested outages.

PSE&G will improve electricity outage management and resolve network failures more efficiently once a critical mass of smart devices has been rolled out. In addition, PSE&G will realize further savings from more targeted and informed investment decisions.

Business plans at other utilities have identified reliability improvements related to faster outage detection and restoration, but those effects may be attributed to other grid modernization investments, such as distribution automation and system hardening. This business case is only focused on the benefits that can be attributed to the deployment of the PSE&G Energy Cloud, leaving the benefits related to faster restoration to the deployment of other grid modernization technologies. For example, the Energy Strong II program is deploying technologies (e.g. TripSavers on branch line connections) that will have a significant impact on improving the system reliability as well. In an effort to avoid double counting, the benefits outlined in this section only cover the incremental reliability benefits that can be attributed to deployment of iESP devices.

Right-Sizing Equipment

Smart devices enable a comprehensive view of the entire distribution system in real-time down to the device. This allows a utility to collect data on planning and resourcing requirements and to naturally leverage the historic data to forecast system planning needs of the future. Thus, the PSE&G Energy Cloud gives the utility a better idea of resourcing demands and requirements, as well as informing the utility if too many customers are connected to one transformer that is continually failing and dropping a large customer load, etc. The ability to right-size equipment provides increased effectiveness of utility service, and, therefore, increases customer satisfaction. There is also potential for the deferral of capital investment by better utilization of current assets. For future system planning, accuracy will become critical as customers engage in energy storage opportunities, solar energy, and use of electric vehicles. The required infrastructure to achieve success of these energy efficient efforts must be identified, evaluated, and sized during the utility system planning process. The type of equipment to be identified includes distribution transformers, capacitors, and fuses.

Normal Functions during Storm Modes

By providing much more granular distribution system awareness to the restoration crews and using more proactive communications to customers during major storm events, PSE&G's storm response teams can eventually expect to handle reduced work volumes (e.g. number of calls to report outages) during these major events. This decreased storm related outage work frees PSE&G personnel to continue their normal operations and reduces the backlog of work (e.g. device reading, new services construction) which may need to be completed using overtime. During Hurricane Harvey in late 2017, CenterPoint Energy was able to generate bills for 700,000 accounts with actual readings (98%+ performance). Without the automation made possible with the device network, the estimated bill volumes would likely have been far higher. High volumes of estimated bills often lead to higher volume of bill dispute and other customer complaints which require additional resources to address.

Proactive Customer Communications

One area where the increased visibility provided by the PSE&G Energy Cloud deployment will enhance customer service is the ability to engage with individual customers with highly relevant messages, especially during outage events. Operators will know exactly which customers are experiencing service disruptions, and they will be able to see whose power has been restored after every restoration step. Customers can opt-in to receive outage alerts that will proactively inform them (across multiple channels) of any disruptions in service, the projected restoration times, as well as any updates to the status of the outage restoration. This proactive communication from PSE&G to its customers will allow customers to make alternative plans during outages, if necessary. Further, PSE&G can use these proactive notifications in area outages or during major storm events to let customers know that the Company is aware of their outages and is actively working on restoring service. In addition to proactively keeping customers engaged and informed about outages, PSE&G can reduce the volume of calls during major events by eliminating a certain percentage of calls reporting outages and by eliminating the need for callbacks. During Hurricane Harvey in 2017, CenterPoint Energy's ability to directly "ping" individual customer devices enabled CenterPoint to let customers know that they did not need to call in to report the outage, as the utility already had that information. This helped CenterPoint to proactively communicate to the customers who were directly impacted, as CenterPoint no longer relied on customer calls to know which customers were out of power.

Carbon Reduction

The increased visibility into the status of the distribution system will provide PSE&G personnel the ability to "ping" devices to determine if there are anomalous voltage conditions or service disruptions, and to verify power restoration status without sending a crew out to investigate. This not only allows information to be brought back much faster, but it also avoids additional service vehicle dispatches and miles driven, which, in turn, allows PSE&G to reduce its fleet miles, fuel consumption and carbon emissions.

The better understanding of electricity consumption patterns and load profiles facilitated by the PSE&G Energy Cloud deployment will enable the electricity suppliers (whether PSE&G or third-party suppliers) to procure energy more precisely, reduce potential ramping needs, and reduce the amount of emissions as a result. Further, any incentives that successfully lower the system co-incidental peak and moves consumption to non-peak times may reduce the need to build additional, relatively high heat-rate peaking units, which will further reduce emissions.

Conservation Voltage Reduction (CVR)

The PSE&G Energy Cloud voltage data enables CVR (on a network or circuit level), which is a technique for improving the efficiency of the electrical grid by optimizing voltage on the feeder lines that run from substations to homes and businesses.

The iESP will allow PSE&G operations staff to actively monitor power quality at customer meters. This visibility will allow PSE&G operations staff to confidently conduct conservation voltage reduction moves (lowering tap changer settings) to reduce voltage levels to be closer to the lower end of permissible distribution voltage levels. Research shows this would result in customers consuming less power, specifically, on average, a 0.6% energy savings for each 1% reduction in voltage. This energy reduction reduces customer bills, utility energy costs, asset loads, and carbon emissions.

Better Load Balancing and DER Integration

In recent years, innovative technology trends have emerged that changed and enhanced utility operations and planning. Some of the major trends include incorporating DERs and storage, utilizing intelligent switching and grid distribution automation technologies, integrating light-emitting diodes (LED) and other energy efficiency enhancements. These changes have made load balancing and power quality of the grid more critical than ever before. With smart devices, PSE&G will be able to view recent load patterns in a particular area in real-time, record the variation in load for that area and enable real-time load and phase balancing, which is expected to reduce unplanned outages and ultimately enable accurate load forecasting in the future.

Customer Power Quality

In addition to interval consumption data, the deployed iESP devices will be able to capture interval voltage levels and flags as well. The voltage data recorded by the devices will enable PSE&G operators to determine remotely if the distribution voltage supplied to their customers is within tolerance (120V ± 5%). Further, PSE&G customer-facing operations personnel can use the voltage levels seen at the customer device to determine (potentially without rolling a truck) if a potential power quality issue (e.g., low voltage, dim or flickering lights) is on the customer side of the device, or is a condition caused by an issue on the PSE&G side of the device. This potentially avoids 12,744 investigative truck rolls per year that are currently used to investigate power quality related complaints.

The knowledge of where voltage levels are sagging will help PSE&G operators to mitigate power quality issues faster, potentially even before affected customers call in to report flickering lights or other voltage issues. The ability to proactively detect these types of issues will enable PSE&G to conduct preliminary diagnoses of power quality issues faster, and present customers with more information, so the best mitigation (either customer side or PSE&G side) measures can be identified.

Outage Detection / Response

PSE&G's outage detection capabilities will be enhanced with the deployment of iESP devices. The ability to help PSE&G crews pinpoint which customers are out will result in faster identification of nested outages. To identify nested outages, PSE&G currently conducts outbound calls (and sends crews to visit customers) to verify if a customer has been restored after repairs to the primary circuits are completed. The automation of this verification stands to reduce or eliminate the need to conduct these outbound calls and the associated ~2,270 investigative truck rolls, equating to $3,967,991 in savings.

Deferral / Reduction of Capital Costs

With better understanding of customer usage patterns and peaks, and the ability to determine effective peak-shifting incentive programs, PSE&G can potentially delay capital intensive distribution capacity increasing projects, which may help to defer capital costs.

3.4 NEXT GENERATION UTILITY AND SMART CUSTOMERS

The rollout of smart devices will play an important role in New Jersey's effort to enable technology that will help to address a number of challenges in the move towards smart energy systems and a smart grid for PSE&G customers. By providing near real-time information on cost and usage, smart devices will encourage consumers to reduce their demand, directly contributing to lower energy bills, energy system resilience, and carbon emission reductions.

The smart energy customer expects:

- Anywhere and anytime available service delivered through multiple, integrated self-service channels, providing low effort, fully functional interactions. Customers can access services through Alexa, Web, mobile, etc.;

- A customized engagement experience, facilitated by data analytics, artificial intelligence and machine learning that predicts customer needs and empowers customers to manage costs, carbon footprint, etc.;
- Proactive offers/tips to reduce energy usage at certain times a day to seamlessly achieve cost savings and participate in an environmentally friendly demand reduction program;
- Smart device installations to help with real-time tracking of home energy usage, efficiency and power issues – PSE&G is committed to offering assistance, programmable communicating thermostats (PCTs) and connectivity to iESP to low-income customers to help them achieve their energy ambitions;
- New products and services focused on customer needs, facilitate bi-directional or mutli-directional engagement and provide predictive alerts and tips around their energy portfolio; and
- Help to keep energy local, clean and cost effective by assisting with rooftop solar, electric vehicle charging stations, etc.

An overview of select smart customer benefits that will be realized beginning with release one of the capabilities enabled by the PSE&G Energy Cloud are included below. A full accounting of smart customer initiatives and capabilities enabled by release one and subsequent releases are identified in chapter 4 of this report.

Customer Engagement / Usage Transparency

Traditional devices allow for a simple record of energy consumption to be collected, mainly by manually reading the device (i.e. by a Meter Reader visiting the site). While this allows for energy bills to be issued, there is limited opportunity for consumers or suppliers to use this information to proactively manage energy consumption. Often suppliers only know how much energy households have actually consumed after they receive their monthly bill. Smart devices allow customers to engage actively with their energy usage and make adjustments as desired. In addition, energy usage of smart appliances can be monitored and recorded. Lastly, inaccurate data and billing create significant costs for suppliers and consumers, causing disputes over bills (complaints), and problems with the overall customer experience. Smart devices avoid potential discrepancies and can enhance the customer billing and payment experience.

3.5 NEXT GENERATION UTILITY AND SMART HOME

The future home will be increasingly connected, robotized, and 'smart'. The smart energy home includes all smart appliances (washers, dryers, refrigerators), smart home safety and security systems (sensors, monitors, cameras, and alarm systems), and smart home energy equipment, like smart thermostats and smart lighting. The PSE&G Energy Cloud will provide universal access to many advanced services.

The smart energy home will enable:

- Customers to engage fully with the energy portfolio and IoT through smart assistants – i.e., "Alexa – what is my energy consumption? Alexa – recommend energy efficiency measures";
- Installation and control of customer-side energy generation sources – solar, electric vehicles, battery storage;
- Smart home analytics that will utilize smart home IoT data to provide interactive metrics and learning algorithms that help all customers manage their home energy and safety, with special assistance for low-income households;
- Connectivity of smart sensors (gas, flooding, motion, CO_2) to ensure customer safety;
- Connectivity of a range of smart appliances, outlets, lighting and other devices through iESP and other IoT connectivity; and
- 'Prosumers' (producer-consumer) participate in the energy marketplace and trade or exchange surpluses with other market participants – Apple, Walmart, Whole Foods and many others are setting up independent energy solutions that will be integrated into the grid marketplace.

A full accounting of smart home initiatives and capabilities enabled by release one and subsequent releases are identified in chapter 4 of this report.

3.6 NEXT GENERATION UTILITY AND SMART PRODUCTS & SERVICES

The PSE&G Energy Cloud will be an open platform for PSE&G and others to develop and offer products and services to a shared customer base.

Smart energy products and services include:

- Data as a service that provides access to data collected by the iESP and analytics to help authorized third parties and customers manage their energy portfolio needs;

- Innovative time-of-use (TOU), capacity and demand response tariff products to enable customer choice for consumers to shift their electricity usage during peak periods in response to financial incentives;
- Support for enhanced appliance management, including beyond the meter smart appliances, sensors and energy efficiency programs, with new integrated customer engagement models through partner applications and capabilities;
- Support for larger scale energy services such as surge protection, weatherproofing, area lighting, energy efficiency and building management & retrofits, and EV infrastructure;
- Network as a service that provides secure and scalable access to the iESP network to enable a customer's connectivity needs – municipal metering, city sensors, safety/security, street lighting; and
- Utility as a service that leverages PSE&G Energy Cloud infrastructure and systems to offer a range of meter-to-cash services for other utilities without these capabilities.

An overview of select smart products and services benefits that will be realized beginning with release one of the capabilities enabled by the PSE&G Energy Cloud are included below. A full accounting of smart products and services initiatives and capabilities enabled by release one and subsequent releases are identified in chapter 4 of this report.

Better Customer Segmentation (Customer Usage Analytics) & Improvement in Marketing Efforts

Through the deployment and integration of iESP, utilities are able to model the energy usage of certain communities, as well as specific profiles and segments for residential households, potentially in real-time, with the objective to provide rates and service more aligned with customers' usage and needs. The transparency of this data allows the utility to compare household energy usage in relation to neighboring households. Utilities have also successfully utilized this data to provide customer-tailored communications showing customers' specific, real-time usage in comparison to their neighbors. In addition to communications, marketing materials can also be better targeted toward identifying ways to save energy and identifying whether a similar customer has enrolled in certain energy savings programs.

Peak Reduction / Peak Shifting

Typically, the highest prices occur during periods of co-incidental system peak demand. Additionally, certain substations or areas can peak at a time that does not correspond to the system co-incidental peak demand. During periods of peak demand on the system or at specific substations, the granular data collected by the iESP allows utilities the ability to identify customers consuming electricity and they can communicate with customers via selected channels with a recommendation to utilize energy outside of the peak demand window. This directly engages the customers in the reduction of their energy bills through the reduction of overall peak demand, and the transparent communication of tips and recommendations to avoid energy use during peak demand times, with an expected rise in customer satisfaction. This can be done before new tariffs are designed to incentivize broad adaptation of specific programs that are scheduled under release two of the use cases.

3.7 NEXT GENERATION UTILITY AND SMART CITY

Smart cities seek to harness digital technology and intelligent design in order to create sustainable and safe cities that increase residents' quality of life. Data is gathered and analyzed from a multitude of sources to achieve this goal. Economies of scale are realized through the sharing of information and coordination of operations across services.

The PSE&G Energy Cloud support of the smart city will include:

- Using sensors and integrated data to monitor and manage traffic and transportation systems, detect environmental issues, power plants, water supply networks, waste management, lighting, law enforcement, public information, schools, hospitals, etc.;
- Enabling community/city microgrids, which are a localized group of electricity sources that normally operate with the traditional electrical grid, but can also disconnect to "island mode" – and function autonomously as physical, safety and/or economic conditions dictate;
- Supporting EV infrastructure, which utilities are well-positioned to provide, by adapting and strengthening the grid for the benefit of EV owners (EVs are still a small fraction of the automotive fleet, but their usage is on the rise);
- Incorporating IoT devices and solutions such as connected sensors, lights, and meters to collect and analyze data, to reduce costs and improve the quality of infrastructure;
- Deploying sustainable energy resources (e.g., rooftop solar, wind, energy storage, EVs, etc.), which are physical and virtual assets, to supplement city energy requirements and meet green objectives; and

- Enhancing communication between citizens and government, allowing city officials to quickly communicate important information to residents on topics such as traffic, public safety, public health, etc., and better address their needs.

A full accounting of smart home initiatives and capabilities enabled by release one and subsequent releases are identified in chapter 4 of this report.

3.8 SELECT ADDITIONAL CAPABILITIES

The implementation of the PSE&G Energy Cloud will create additional opportunities to realize benefits ***beyond those noted in release one*** that were quantified as part of this business case. An additional 48 initiatives and capabilities are anticipated to be supported by the PSE&G Energy Cloud as part of releases two through four in the deployment roadmap but will require further development before they are ready for implementation.

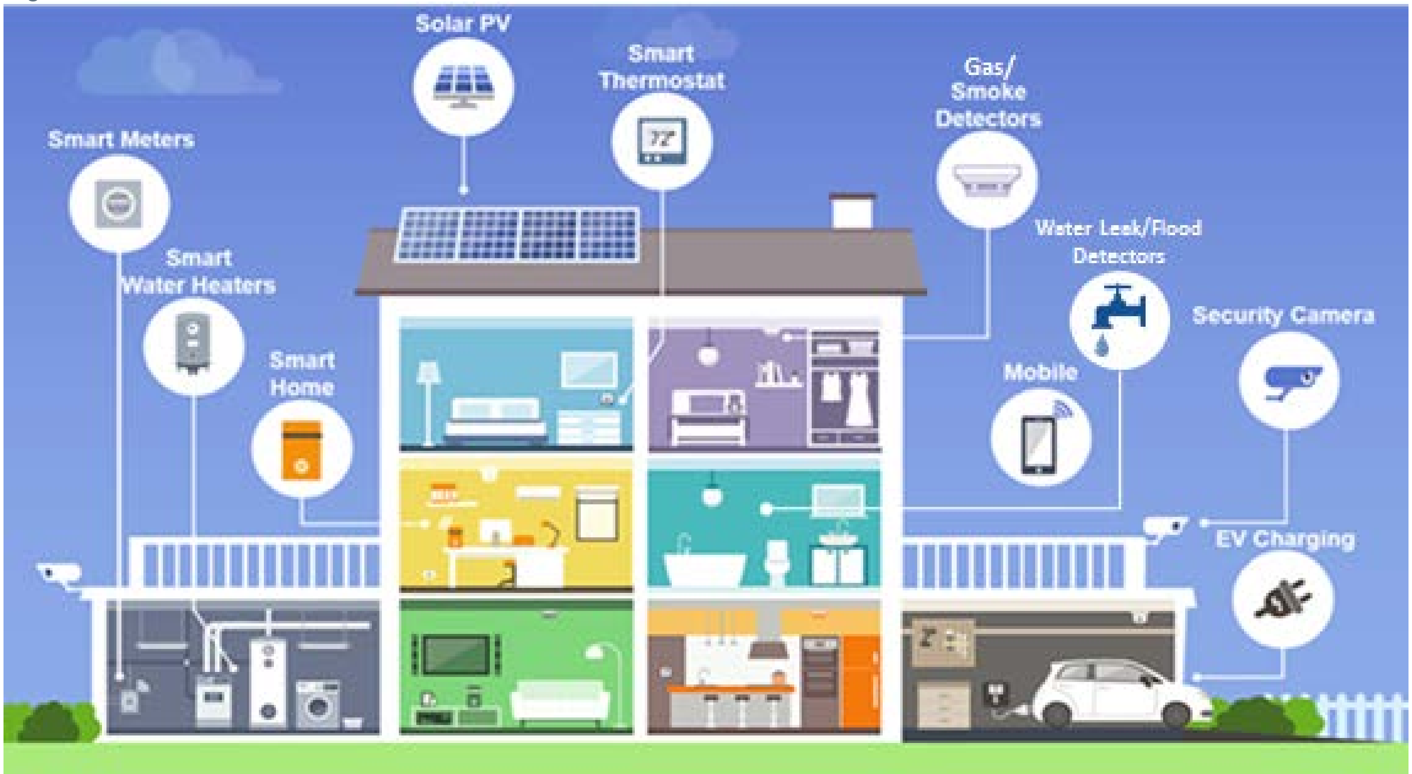
The capabilities discussed below are for select use case initiatives included in releases two through four and highlight the benefits of demand-side variable pricing programs, customer pre-pay, bi-directional electricity measurements and demand charges, energy efficiency, and streetlight dimming / part-time scheduling. Where possible, the potential benefits of these opportunities are presented in the context of benefits realized at other utilities that have implemented similar programs. Furthermore, many of these programs are enabled or enhanced by the capabilities realized when customer systems are integrated into the process.

Customer Systems Integration (Smart Home)

The business case currently contemplates rolling out a company web portal to allow customers to view the additional data made available by the PSE&G Energy Cloud and installing PCTs at the premises of a subset of PSE&G’s customers. PCTs and a series of other customer-side technologies will be required to support and/or enhance certain future capabilities resulting from the rollout of iESP. The integration of iESP and PSE&G systems with PCTs, in-home displays (IHD), home area networks (HAN), direct load control (DLC) devices, and energy management systems will allow for the automated control of customer systems and exchange of information fundamental to many of the future capabilities described below.

- Control technologies such as PCTs and DLCs allow for the automatic control of high use devices such as heating, ventilation and air conditioning (HVAC) and other systems, and appliances can be set up to respond automatically to price signals, load conditions, or other triggers with the installation of HANs and energy management systems.
- Information technologies such as IHDs, company web portals, and automated communications across text and email channels can provide customers with more granular and timely data about their energy usage and the cost of this consumption. These can be utilized to support, among other things, demand-side programs through the provision of specific information to allow the customer to make informed decisions about their usage.
- Home energy management including smart appliances reporting usage and power consumption in real-time, devices that educate customers about their energy consumption, and systems that identify preventive maintenance on appliances before they break down.

Figure 3-2: Customer Connected Home



Solar PV

Arizona Public Service Electric Company's Solar Program, already in its fifth year provides 1,500 qualified homes in the state with utility-owned rooftop solar panels at no cost to the homeowners. Participants in the program receive a $30 bill credit each month for the next 20 years. *(Source: APS)*

Smart Water Heaters

Under certain market conditions a smart water heater could earn its owner between $172 and $216 per year, more than covering its cost of installation over five years. *(Source: NRDC & NRECA)*

Smart Thermostats

Nest's smart thermostats can save customers a reported 15% on heating and cooling bills – translating to an estimated average savings of $131 to $145 a year. There are now increasingly more market players including Venstar, Amazon's Ecobee and Honeywell in this space. *(Source: Forbes & PA Consulting)*

EV Charging (Electric Vehicles)

Despite California being the state with by far the most EVs (over 180k) it is no longer the fastest growing. By state, Utah (over 60%), Nevada, North Carolina, Colorado, and Kansas saw the fastest EV growth rates in 2016. *(Source: California PEV Collaborative and ChargePoint)*

Smart Meters

In 2016, U.S. electric utilities had about 64.7 million AMI meter installations with about 88% of the AMI installations being residential customers. *(Source: EIA)*

Smart Home
(Home Automation, Home Security, Smoke Detectors)

In 2014, Houston based electric utility, Direct Energy, launched a partnership with SmartThings which offered customers starter kits which included a Hub, sensors and controllable devices focused on energy management, basic home security and home automation, such as smart power outlets, smart lighting, motion sensors and open/ close sensors.

All smart devices in this catalogue are connected to each other and communicate through the SmartThings mobile app which offers customers remote control of these devices. *(Source: Direct Energy)*

Mobile

83% of utility executives believe that customers will desire more opportunities to perform mobile transactions. *(Source: Utility Dive)*

New Rates & Demand-Side Programs (Smart Products and Services)

Information from the PSE&G Energy Cloud, subject to appropriate data, privacy, and access control arrangements, will enable more sophisticated energy usage profiles and, therefore, new tariff structures and energy demand management approaches. This will enable the implementation of demand-side programs, foster customer choice, and generate savings, both in terms of distribution as well as generation capacity investment. The analysis in this business case quantifies the benefits associated moving a subset of customers to new rate classes based on energy use, however there exists great potential to move customers to new rate designs but the specifics of the demand-side programs delivering these benefits will need to be finalized as part of release two of the PSE&G Energy Cloud capabilities as noted in the use case road map.

Demand-side programs are comprised of time-based rates and incentive-based programs and have been implemented by utilities in an effort to encourage customers to reduce electricity consumption by shifting consumption away from peak usage periods or through electricity conservation. Time-based rates come in many forms and offer various prices for electricity consumption based on the time of day, week, or month. Under these programs, electricity prices are typically highest when wholesale supply costs and demand are highest (i.e., hot summer afternoons). The objective is to use price signals to shift customer electricity consumption in order to achieve demand-side load relief. Similarly, customers enrolled in incentive-based programs receive compensation for reducing or foregoing consumption when called on by the utility to do so, typically during high demand periods and/or emergency conditions. Utilities can offer time-based rates separate from or concurrently with incentive- based programs. These programs can be offered across the system or, for example, at the substation level in order to address more localized issues. Additionally, service territory-wide programs can be tailored to address voltage and loading issues that occur at different times of day across different areas and substations.

Examples of time-based rates[4] include:

- **Time-of-Use (TOU)**: typically applies a constant predetermined price over a broad block of hours (e.g., on-peak summer weekdays) in an effort to shift consumption to off-peak periods.
- **Real-time Pricing (RTP)**: typically applies to usage over a specific increment of time (e.g., 5-minute, 30-minute, hourly, etc.) where the price differs across each increment in an effort to shift consumption to off-peak periods.
- **Tiered Pricing**: typically charge a different price based on blocks of usage (e.g., first 500 kWh vs. next 500 kWh) during a given period of time (e.g., 30-day billing cycle) in conjunction with state-approved tiers.
- **Variable Peak Pricing (VPP)**: a hybrid of TOU and RTP where the different periods for pricing are defined in advance (e.g., on-peak summer weekdays), but the various price levels established for the on-peak period differ to reflect the cost of delivered electricity. VPP rates are designed to shift consumption away from peak periods in general and reduce consumption during periods of exceptionally high low or emergency conditions.
- **Critical Peak Pricing (CPP)**: a construct under which a utility can call a critical event when it anticipates or experiences high wholesale market prices or emergency system conditions and raise the rate. CPP rates can be fixed at a predetermined rate for each critical event or vary based on system demand during the critical event. CPP rates are designed to reduce a customer's consumption on a limited number of days when critical events occur.
- **Critical Peak Rebates (CPR)**: offered when a utility calls a critical event during pre-specified time periods (e.g., 3 pm - 6 pm summer weekday afternoons) in response to anticipated or observed high wholesale market prices or emergency system conditions. The price for electricity remains the same during these periods but the customer is refunded at a single, predetermined value for any reduction in consumption as determined by the difference in what the utility deemed the customer was expected to consume and their actual consumption.

Examples of incentive-based programs[5] include:

- **Direct Load Control**: where the utility has direct control over designated customer appliances and equipment (typically via radio-controlled switches). Customers agree to have their power to the devices turned off for a financial incentive during predetermined peak periods, with the number of interruptions typically capped during the year.
- **Interruptible and Curtailable Rate Programs**: financial incentives are provided, typically to large commercial and industrial customers, for load reductions to predetermined levels during emergency events.

The benefits attributable to demand-side programs fall under three general buckets (see figure 3-3)[6].

[4] "DEMAND REDUCTIONS FROM THE APPLICATION OF ADVANCED METERING INFRASTRUCTURE, PRICING PROGRAMS, AND CUSTOMER-BASED SYSTEMS – INITIAL RESULTS," U.S. DEPARTMENT OF ENERGY: ELECTRICITY DELIVERY AND ENERGY RELIABILITY, DECEMBER 2012.
[5] IBID.
[6] IBID.

Figure 3-3: Demand-Side Program Benefits

Expected Benefit	Source of the Expected Benefit
Deferred capital expenditures and improved capital asset utilization	• Reduced or delayed requirements for power plants and power lines • Reduced capacity payments or other peak demand charges • Lower peak demands from customers' participation in time-based or incentive-based programs measured by kilowatt or megawatt reductions
Reduced energy generation and environmental impacts	• Reduced combustion of fossil fuels and lower emissions of air pollution, including carbon emissions • Reduced land and water use requirements for power plants and rights-of-way for power lines • Reduced electricity consumption from customer participation in information-based programs measured in kilowatt-hour or megawatt-hour reductions
Expanded customer options for managing electricity consumption and costs	• Financial incentives (through new rates and programs) for customers to change their electricity consumption patterns, including possibly lower bills • Devices and systems for better customer acceptance through information and automated controls

IMPACT OF SELECTED DEMAND-SIDE PROGRAMS

Using funding made available under the American Recovery and Reinvestment Act of 2009, the Department of Energy (DOE) established the Smart Grid Investment Grant (SGIG) program. SGIG money was awarded to fund, among other things, 70 projects under which utilities implemented iESP and customer system technologies. A total of 26 SGIG utilities piloted one or more time-based rates or incentive programs, with a total of 417,000 customers participating in the pilots. A subset of ten utilities partnered with the DOE to conduct consumer behavior studies (CBS) to gauge customer acceptance, retention, and response to time-based rates. The CBS employed randomized and controlled experimental designs as part of the analysis that were governed by technical guidelines develop by the DOE. A compilation of the CBS findings around customer demand reduction and enrollment and retention rates broken out into following five general areas are presented in figure 3-4[7]:

- Recruitment approaches – effects of opt-in and opt-out;
- Pricing vs. rebates – effects of CPP and CPR;
- Customer information technologies – effects of IHDs;
- Customer control technologies – effects of PCTs; and
- Customer response to prices – effects of TOU.

The full report presents abundant discussion around the program characteristics and results, including cost-benefit results for selected utilities. A summary of the programs initiated by the utilities participating in the CBS are included in the DOE CBS Participant Demand-Side Programs Appendix.

[7] "FINAL REPORT ON CUSTOMER ACCEPTANCE, RETENTION, AND RESPONSE TO TIME-BASED RATES FROM THE CONSUMER BEHAVIOR STUDIES," U.S. DEPARTMENT OF ENERGY: ELECTRICITY DELIVERY AND ENERGY RELIABILITY, NOVEMBER 2016.

Figure 3-4: CBS Summary of Findings

Area	Major Findings – Demand Reduction and Enrollment / Retention Rates
Recruitment approaches – opt-in and opt-out	• Opt-out enrollment rates were about 3.5 times higher than they were for opt-in (93% vs. 15%) • Retention rates for opt-out recruitment approaches (85.5% in year 1 and 88.5% in year 2) were about the same as they were for opt-in (89.7% in year 1 and 91.0% in year 2) • Peak period demand reductions for one participant's Sacramento Municipal Utility District opt-in TOU customers were about twice (13% in year one and 11% in year 2) than they were for opt-out customers (6% in year 1 and 2) • Peak period for Sacramento Municipal Utility District's opt-out CPP customers were about 50% higher (24% in year 1 and 22% in year 2) than they were for opt-in customers (12% in year 1 and 14% in year 2) • Sacramento Municipal Utility District's opt-out offers were more cost-effective for the utility than their opt-in offers in all cases • Roughly two-thirds of those who were defaulted into Sacramento Municipal Utility District's TOU rates were expected to see bill impacts of +/- $20 for the entire 4 summer months the rates were in effect • Based on surveys responses, a majority of those defaulted onto Sacramento Municipal Utility District's TOU rate were satisfied with the rate, regardless of the level of bill savings achieved, but those who saw the largest bill increases were generally less interested in continuing with the rate after the study ended
Pricing vs. Rebates – CPP and CPR	• While opt-in enrollment rates for one participant Green Mountain Power were about the same for CPP (34%) and CPR (35%), retention rates were somewhat lower for CPP (80%) than they were for CPR (89%) • Average peak demand reductions during an event for CPP (20%) were about 3.5 times higher than they were or CPR (6%), but when automated controls (PCT) were provided, they were about 30% larger (35% for CPP and 26% for CPR)
Customer Information Technologies – IHDs	• Enrollment and retention rates were generally unaffected by offers of IHDs • Sacramento Municipal Utility District's opt-in CPP customers with IHDs (26% in year 1 and 24% in year 2) had somewhat higher peak demand reductions than those without IHDs (22% in year 1 and 21% in year 2), but these differences can be explained by pre-treatment differences between the two groups • Sacramento Municipal Utility District's opt-in TOU customers with IHDs (13% in year 1 and 11% in year 2) had somewhat higher peak demand reductions than those without IHDs (10% in year 1 and 9% in year 2), but these differences can be explained by pre-treatment differences between the two groups • Sacramento Municipal Utility District's offerings without IHDs were more cost-effect for the utility in all cases than those with IHDs
Customer Control Technologies – PCTs	• Enrollment and retention rates were generally unaffected by offers of PCTs • Peak period demand reductions are generally higher for CPP and CPR customers with PCTs (22% to 45%) than they were for customers without PCTs (-1% to 40%) • Oklahoma Gas & Electric rate offers with PCTs were most cost-effective for the utility than those without PCTs
Customer Response to Price – TOU	• Peak period demand reductions were far less, on average, for the lowest peak to off-peak price ratios (6% for treatments with a peak to off-peak price ratio less than 2:1) than for the highest price ratios (18% for treatments with a peak to off-peak ration greater than 4:1) • When a CPP/CPR was overlaid on a TOU rate, the average peak event demand reduction rose to 27% when averaged over all of the treatments • When PCTs were available, the differences in average peak period demand reductions were only affected at peak to off-peak ratios in excess of 2:1 (21% vs. 10% for price ratios between 2:1 and 3:1 and 23% vs. 15% for ratios in excess of 4:1)

Customer Pre-Pay (Smart Products and Services)

Customer pre-pay is a capability included in release two of the PSE&G Energy Cloud capabilities as noted in the use case road map and the benefits have not been quantified as part of the business case. Pre-pay programs provide benefits for both customers and the utility. A pre-pay program can help digitally inclined customers who have an interest in understanding their electricity consumption and identifying the drivers for bills that may be different than expected, and/or those customers needing assistance in managing consumption and costs. The direct impacts of pre-pay are typically a reduction of reconnection fees.

PRE-PAY FINDINGS

Findings from a few pre-pay pilots and a maturing utility-wide program at Salt River Project offer insights into the potential of pre-pay:

- Salt River Project reports a 12% reduction in energy use, on average, for participants in its pre-pay program. The program has 154,227 participants who utilize in-home displays to access information about their usage. The reduction in load realized as a result of the plan equates to 59 MW over the course of a year. Salt River Project currently has 120 pay center machines located throughout metro Phoenix that accept payment for the program and the next generation pre-pay plan they are developing will allow participants to pay using their computer or smartphone and view usage online.
- Duke Energy asked customers who are participating in its pre-pay pilot about their satisfaction with the program and 41 of 51 (80%) respondents noted that the pre-pay pilot had “a positive effect” on their satisfaction with the company, while 6 customers said it had “a negative effect” and 4 responded it had “no effect.”
- Talquin Electric Cooperative, with 56,000 customers in northern Florida, decreased its bad debt write-off by over 65% since 2011 due in part to its pre-pay program. The program allows customers to apply a portion of this money towards existing balances and the rest toward future use in order to pay overdue utility bills.
- Sioux Valley Energy, with 27,641 customers in South Dakota and Minnesota, implemented a pilot that allows customers to sign up for pre-pay with a minimum of $25 and allocate 50% of the funds to past due bills and 50% to future electricity use. This reduced the amount charged to customers for collection trips by about 50% from 2007 to 2014.

Bi-Directional Electricity Measurements and Demand Charges (Smart Network)

The ability of the PSE&G Energy Cloud devices to measure in near real-time the magnitude and direction of electricity flows to customers over the course of the day allows utilities and regulators to consider a more equitable accounting of the grid resources required to generate and deliver electricity for a particular customer.

Historically, residential electricity consumption and consumption patterns have not varied much from one customer to another. The typical load profile followed a predictable curve where consumption was lowest overnight, increased as people woke up and prepared to go out for the day, decreased through midday, then peaked as people returned from their day before decreasing as they went to bed. Because there were limited differences in total and temporal consumption between customers, utility rates combined the energy and demand components of service together in a single charge.

The introduction of numerous technologies that impact consumption, such as PCTs, plug-in EVs, rooftop solar, energy storage, etc., and varying adoption rates across residential customers means the historical relationship of energy consumption across customers no longer holds. Customers making use of technologies that shift electricity consumption from periods of peak demand to off-peak periods, such as smart appliances and storage as discussed above, are smoothing their load curve and reducing the costs for grid resources to meet increasing demand but are not being rewarded with a lower demand charge. Conversely, customers who install rooftop solar are creating an even larger spike in demand in the afternoon as the output of rooftop solar typically drops to zero as people return home and demand spikes. The increase in demand is more pronounced for these customers as it increases from zero consumption for customers that were net exporters of electricity to very high demand as the sun goes down in a short period of time. This type of load spike requires more grid resources to meet the surging demand.

Another future capability area enabled in part by iESP infrastructure and data, and the inherent bi-directional flows available, is the enhancement of customer engagement through the creation of distribution level marketplaces that support peer-to-peer energy trading and the development of new energy related products & services. Three types of marketplaces are possible, including:

- Marketplaces at the customer “Mass Market” level –- composed of products (e.g., rooftop solar photovoltaics) and services (e.g., demand management) that allow for customers to create, reduce and trade consumption of energy, a vast difference from today’s non-transparent, high barrier, uncertain return and significant customer education time investment environment.
- Markets at the wholesale market level –- open up to include larger-scale DERs interconnected with the distribution system and providing energy into the wholesale market.
- Markets at the distribution system “Grid Services” level –- present opportunities for DER providers to offer services to the distribution grid, such as ancillary services.

Ultimately, it is envisioned that a transparent and unified market will emerge for customers, DERs and other third-party services that is animated and fully transactive. In the short run, it is expected that expanded DER will dominate followed by customer markets.

Energy Efficiency (Smart Customer)

The consumption pattern data from the PSE&G Energy Cloud will enable PSE&G to develop more targeted programs for energy efficiency. The data can potentially be used to help customers identify which appliances are functioning sub-optimally, and it will help customers make more informed economic decisions for replacing less efficient appliances (through a much better understanding of how the increased efficiency leads to savings). This energy efficiency capability would be in addition to that tied to the PCTs offered as part of release one of the PSE&G Energy Cloud.

Streetlight Dimming / Part-Time Scheduling (Smart City)

Using the iESP infrastructure to enable remote control of streetlight operations is included in release two of the PSE&G Energy Cloud capabilities as noted in the use case road map and the benefits have not been quantified as part of the business case. Certain capabilities associated with remote streetlight control have been identified in PSE&G's Clean Energy Future filing and these would be complemented by the functionality of iESP infrastructure.

Smart streetlights will have the capability to be controlled remotely and would have the ability to report back if a particular streetlight light has malfunctioned. The ability to remotely determine if a streetlight has malfunctioned would: 1) avoid night time patrols needed to determine which streetlight has failed, and 2) allow PSE&G to dispatch repair crews to only the failed streetlights (in 2017, of the dispatches for streetlight outages, PSE&G dispatched ~2,600 streetlight crews to streetlight related calls where it was determined that there were no issues with the lighting or that the lights did not belong to and were not serviced by PSE&G). The communications network could be used to accommodate the advanced control features on streetlights, which would enable the end users (whether they are municipalities or individual streetlight customers) to provide on-demand dimming or time-varying lumens output (e.g. dimmer during night time hours with no street traffic). Finally, the ability to prove if a particular streetlight is operational should improve public safety.

PSEG

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THE PLAN FOR THE PSE&G ENERGY CLOUD

4 THE PLAN FOR THE PSE&G ENERGY CLOUD

PSE&G has developed a strategic deployment roadmap for the PSE&G Energy Cloud identifying, among other things, the timing of the deployment of the foundational iESP infrastructure and when the initiatives and capabilities, or use cases, that rely on the iESP will be implemented. A total of 70 uses cases have been identified for the PSE&G Energy Cloud that will enable the company to transition to a leading smart utility of the future.

The prioritized roadmap is based on the list of PSE&G applicable use cases and covers both “Foundational” and “Future” use case requirements that will be realized over a series of four releases. The benefits associated with the capabilities delivered with release one have been quantified in this business case to articulate the expected incremental value/benefits of investment (VOI), as well as the expected qualitative benefits to customers and PSE&G.

4.1 USE CASE PRIORITIZATION AND ROADMAP

PSE&G’s business and IT representatives selected 70 use cases as applicable to the program based on their:

- Applicability to PSE&G’s business;
- Relevancy to iESP, best practices, and current company filings;
- Grid modernization and enhanced customer engagement focus; and
- Foundational, advanced, and long-term aspirational capability and value generation.

The 70 use cases were then broken out by their level of sophistication and assigned to one of four release tranches based on the ease of deployment and maturity of the business unit capabilities supporting the opportunity. The use cases were determined to be either foundational, advanced, or future enabled based on the following characteristics:

1. Foundational / Upgrade – use cases that can be fully deployed and enabled with none or minor additional iESP capability upgrades and are key dependencies for “advanced” or “future enabled” use cases.
2. Advanced – use cases that can be fully deployed and enabled with additional and advanced iESP capabilities (sensors, control boards, street lighting, data streams, etc.) and are key dependencies for “future enabled” use cases.
3. Future Enabled – use cases that can be supported partially by iESP (data, network), but require additional and external capabilities (SAP, CRM, Smart City, rate approval, internet, advanced analytics) to fully realize potential.

The use cases identified for release 1 are a practical mixture of all use case types that are supported with few, if any, upgrades beyond the iESP deployment. The use cases included in releases two and three are predominantly advanced, while the use cases included in release four typically require additional external capabilities and are classified as future enabled.

Figure 4-1: PSE&G Energy Cloud Use Cases and Release Groups

PSE&G Applicable Use Case Capabilities (70) – On the Roadmap

Release 1 – with iESP (22)

1. Enhanced Customer Engagement & Communications
2. Rate Analyzer & Comparator
3. Usage & Bill Alerts, Saving Tips
4. Interactive Energy Demand & Bill Management
5. Customer Segmentation & Behavioural Analysis
6. Customer Power Quality
7. Customer Energy Efficiency (Smart Thermostats)
8. Customer Service & Call Center Performance
9. Customer DER/PV/EV
10. Customer Device Safety
11. iESP Sensor, Network & Data Operations
12. Remote Move in / Move Out
13. Remote Disconnect / Reconnect
14. Next Generation Meter to Cash
15. Network Connectivity Analysis
16. Outage Detection & Restoration
17. Outage Response Notification (ETR)
18. Voltage Monitoring & Analysis
19. Asset Load/Phase Management, Balancing & Power Analysis
20. Load Profiling & Forecasting
21. Distribution Losses
22. Revenue Protection & Assurance

Release 2 (15)

1. Customer Demand Response
2. Asset Management & Health
3. Reliability Analysis, Optimization, & Cost/Benefit
4. Distributed Generation Analysis
5. System Planning & Investment Portfolio
6. Distribution Automation & SCADA
7. Street-Lighting Remote
8. Customer Pre-Pay
9. Innovative Rate Development
10. Customer Smart Home/Appliances/Devices
11. Network as a Service
12. Data as a Service
13. Critical Peak Pricing
14. Demand Response Control
15. Conservation Voltage Reduction

Release 3 (16)

1. Smart City
2. Microgrids
3. Innovative/New Products & Services
4. Customer Gamification & Loyalty Programs
5. Distribution/Bi-Directional Marketplaces
6. Asset Performance, Maintenance & Visualization
7. Load Curtailment / Limiting
8. Advanced Auto Detection & Location
9. Automated Fault Isolation & Restoration (FLISR) – Self Healing
10. Volt / VAR Optimization & Control (VVO/VVC)
11. Customer Safety (Gas Leak, Co2)
12. Permanent Power Quality Management
13. Utility, Customer, & Community Energy Storage
14. Asset Risk Analysis and Risk Scoring
15. Optimal Switch / Recloser Placement
16. Dynamic Circuit Reconfiguration

Release 4 (17)

1. Load Control, Adjustment, Optimization, & Contingency
2. Customer Building Automation Optimization
3. Real-Time-Pricing
4. Storm/Lightning Analysis
5. Vegetation Management
6. Environmental / Sensitive Area Analysis
7. Storm Prediction
8. Advanced DER Planning & Management (DERMs)
9. Control of DERs and HVAC Equipment
10. DER Operations & Control
11. Battery Aggregation & Control
12. PV/DER Output Forecasting
13. Real-Reactive Load-Voltage Management
14. Optimal Capacitor Bank Design & Placement
15. Switching Schedule & Safety Management
16. Ancillary Services
17. Energy Management & Frequency Control

Descriptions for each of the 70 use cases are included in figure 4-2 below. Note that the use cases for which benefits have been quantified and included in this business case are colored red and include all the use cases included in release one plus.

FIGURE 4-2: PSE&G Applicable Use Case Inventory Definitions

Release #	Use Case #	Use Case Name	Use Case Overview
1	1	**Enhanced Customer Engagement & Communications**	A set of customer-benefiting functions and analytic applications that provide visualizations and information to customers, through bi-directional communications channels, including mobile and web portals, Home Area Networks (HAN), etc.. Other features connected to interfaces would include: Neighbor/Peer Gaming & Loyalty Programs. These Use Cases are enabled in part by expanded use and volumes of iESP data combined with the communications network.
	2	**Rate Analyzer & Comparator**	The ability to analyze customers usage profile and provide rate options that would fit that profile and meets customer needs for green outcomes, reduced bills, etc..
	3	**Usage & Bill Alerts, Saving Tips, Interactive Bill Presentment**	Alerts that would be set by the customer and PSE&G to warn or notify customers of usage outside normal parameters, tips within their current rates to reduce bills, etc..
	4	**Interactive Energy Demand & Bill Management**	Customer analytics capabilities that allow the customer to interrogate their energy and billing profile with the aim of the customer becoming informed and engaged, and then be able to leverage the use cases above to make required changes.

Release #	Use Case #	Use Case Name	Use Case Overview
1	5	**Customer Segmentation & Behavioral Analysis**	Highly targeted segmentation models based on usage and interaction to improve customer engagement, energy efficiency and peak load reduction. Micro segmentation of customer support and targeted marketing messages, customer sentiment analysis, and analytics to improve customer engagement in utility programs. Using iESP and other customer and market/demographic data to analyze and determine customer energy behavioral patterns. This use case is critical to the introduction of time, tiered or demand based rates or other tariffs, products and services.
1	6	**Customer Power Quality**	Using the connectivity model and iESP data actual voltage is captured and analysis completed to assess voltages. Voltage readings (if they exist) from meters are also captured, factored in and displayed. PSE&G can utilize this information for accurate analysis for potential customer power quality issues. This application helps drive additional value from an investment in smart meters by utilizing the data to identify power quality issues without the need for further instrumentation, and can also help verify data coming back from customers, meters and other sensing devices.
1	7	**Customer Energy Efficiency Programs**	In this Use Case, the customer is given an ability to make more educated energy related decisions, such as participating in load reduction programs, reducing PEV load or charging times, installing energy efficient systems and potentially changing energy consumption habits. These decisions are based in part on being able to provide customers with expanded iESP data through web or mobile portals and in-home devices.
1	8	**Customer Service & Call Center Performance**	At its core, call center performance analytics has two main components — call center analysis and customer operations improvement. Both are vitally important. While it is critical to thoroughly capture and analyze information about call center performance, the ultimate goal is to use a broader range of information (including iESP) to improve service, improve customer satisfaction, and lower cost by bringing together historical and real-time information to support decision analysis and improve the customer experience and product development. This use case supports the provision of iESP data into call center systems to enable better service (within the scope of that data) and also support the Customer 360 initiative.
1	9	**Customer DER/PV/EV**	This Use Case establishes the people, process and technology elements for the analysis, planning and advisory services and information provided to customers in relation to their PV/EV and other distributed energy resources requirements. This would include the management and locating of customer side EV charging and battery storage (dedicated and EV). The initial deployment of this Use Case will establish PSE&G's ability to assist customers with DER installations and the management of any power quality issues that occur.
1	10	**Customer Device Safety**	This Use Case deploys capabilities that use smart device data to detect safety issues relating to customer devices (meters, sensors) - hot sockets, wires down, etc.
1	11	**iESP Sensor, Network & Data Operations**	This Use Case establishes the people, process & technology elements required to manage the iESP Infrastructure deployment and the ongoing and new Meter Operations business function. In both cases this will cover the following business processes - acquisition, warehousing, testing, installation, maintenance, health (asset & communications), data streams and quality, alarm management, meter data management, communications, etc.
1	12	**Automated Move in/Move out & Remote Disconnect/ Reconnect**	This use case addresses the messages exchanged between Customer Operations processes and Smart Meter through the HeadEnd and Network when a customer move in or out request is issued by Customer Operations or other customer processes. PSE&G currently sends a metering service employee to move a customer in or out for a variety of reasons. With iESP, the turn on functions and on demand read functions to support these processes can be automated and performed remotely and instantaneously, thereby increasing customer satisfaction and efficiency across various customer processes. • Electric operations reduction due to MIMO and Collection activity automated. • Gas operations reduction due to remote MIMO and Collection activity automated: • Cost reduction due to avoided truck roll costs for move in move outs
1	13	**Remote Disconnect/ Reconnect**	This use case addresses the messages exchanged between Customer Operations processes and Smart Meter through the HeadEnd and Network when a meter connect/disconnect request is issued by Customer Operations or other processes. PSE&G currently sends a metering service or collections employee to connect or disconnect the meter for a variety of reasons. With iESP, the reconnect/disconnect functions to support these processes can be automated and performed remotely and instantaneously, thereby increasing customer satisfaction and efficiency across various customer processes. • Electric operations reduction due to remote turn-on/off of electric meters. • Gas operations reduction due to remote turn-on/off of electric meters: • Cost reduction due to avoided truck roll costs for Move in standard turn on turn offs • Cost reduction due to avoided truck roll costs for cut at pole/cut and manhole TOTO type events • Reduction in write offs due to energy consumed on inactive accounts. Being able to remotely detect and disconnect will reduce the occurrence.

Release #	Use Case #	Use Case Name	Use Case Overview
1	14	**Next Generation Meter-to-Cash**	With more granular and quality iESP data available, alongside numerous other internal data sources, PSE&G can optimize and re-invent their meter-to-cash processes and drive out inefficiencies, increase service, and reduce costs. The iESP data is significantly more accurate at the source and by mapping the data from the iESP to its end use, leakage can be detected more easily. The cost of these losses is spread across the customer base so any improvement ultimately reduces customer bills. • Billing cost reduction due to a decline of billing irregularities and analysis work: • Collection cost reduction due to a decline of backoffice collection workload: • Reduction in bad debt due to improvement in field collections. Being able to remotely detect and disconnect will reduce the occurrence.
1	15	**Network Connectivity Analysis**	A Distribution network usually covers a large area and provides power to different customers at different voltage levels. So locating required sources and loads on a larger GIS/Operator interfaces is often very difficult. Panning & zooming provided with normal SCADA does not cover the exact operational requirement. The required scope of the network model has now extended to the iESP meters and a high level of accuracy of the network model is also a key prerequisite (and foundational data source) for many other use cases. This use case would support the management of 3 phase supplies and allow enhance phase identification and problem detection.
1	16	**Outage Detection & Analysis**	Uses the network model, advanced algorithms, and outage data from SCADA, sensor and iESP to identify possible outage locations, network sections and customers that are out and protection devices that operated (e.g. fuse blowout, recloser operation). Data is geospatially displayed in real-time, to allow analysis, fast response and crew dispatch to the precise location (down to meter) with information on the potential cause of the outage in order to restore power quickly. Automatically identify the number of customers affected by the outage, verify the outage/restoration by pinging devices and track the restoration in real-time. Improves response time to outages as well as proactively notifying customers through integration to other systems such as Interactive Voice Response (IVR on calls), customer information system (CIS), and outage management system (OMS).
1	17	**Outage Response Notification (ETR)**	This purpose of the outage estimated time of restoration (ETR) use case is to provide analytic and automation to calculate, and communicate reasonable, accurate and acceptable outage status and information to customers (in real-time) such that the overall experience, satisfaction and trust with the utility increases. Solutions within scope of this Use Case include IVR, web portals, SMS (in/outbound), social media, mobile applications, and press releases. iESP data can be used to increase the accuracy of the calculations and messaging in this use case.
1	18	**Voltage Monitoring & Analysis (Power Quality Analysis)**	Using the connectivity model, smart meter data is imported and aggregated to the distribution transformer. Powerflow analysis is run to calculate voltages. Voltage readings (if they exist) from meters are also captured, factored in and displayed. System-wide analysis is run to determine locations with voltage violations both above and below nominal voltage. Utilities can utilize this information for accurate analysis for Volt/VAR Optimization and Management. This application helps drive additional value from an investment in iESP by utilizing the data to identify power quality issues without the need for further instrumentation, and can also help verify data coming back from meters and other sensing devices. Further, it can help identify strategic locations for deployment of Volt/VAR optimization equipment. This use case is a key dependency of CVR.
1	19	**Asset Load/Phase Management, Balancing & Power Analysis (incl. Transformer Load Monitoring (TLM) & Customer Load Curtailment/Limiting)**	Using the connectivity model, iESP data is imported and aggregated. Power flow analysis is run to examine and monitor loading profiles of each and every asset along the feeder from the substation to the distribution transformer to the phasing and meter. This use case gives visibility of loading profiles of substations, feeders, feeder sections, underground cables, fuses, switches, DA equipment, distribution transformers and customers with real-time or overnight meter data updates. This information can be used to determine areas of overloading of assets or the system, and for major events help plan and execute asset balancing, or customer load curtailment or limiting to mitigate peak events. This use case would also support load distribution and balancing related to customer and grid DER assets.
1	20	**Load Profiling & Forecasting**	Load profiles can now be enhanced using iESP data through combination with distribution network, customer billing or other data. Actual demand can now be collected at meters to perform more detailed load analysis; this is beneficial to both distribution and end-user customers for enhanced energy profile data to support core planning and reliability functions.
1	21	**Distribution Losses**	Distribution losses can be identified by comparing the iESP data and feeder / substation level SCADA data, while accounting for street light consumptions. Potential rating changes as a result of temperature or loading on adjacent lines may increase the losses on a particular feeder, especially during contingency scenarios. Areas of high losses or feeders with particularly high losses can be identified through the analysis. Further analysis on the causes of the high losses will shed light into the different types of corrective / mitigating actions that can be taken to reduce the technical losses on a macro level.
1	22	**Revenue Protection &**	Revenue Assurance refers to the prevention, detection and recovery of losses caused by

Release #	Use Case #	Use Case Name	Use Case Overview
		Assurance	interference with or theft of electricity, water, and/or gas service. This use case will leverage smart meter consumption, voltage and event data to detect energy theft and meter tampering by employing multiple screening techniques including cross-service correlations. In addition, this use case will consider the integration of revenue protection (e.g. theft) with other utility activities which impact the meter-to-cash process more broadly such as malfunctioning meters and equipment. Most critically, the use case should integrate detection with field investigations to help improve process efficiency.
2	1	**Customer Demand Response**	PSEG's iESP infrastructure can provide information on energy use as well as alerts and updates and price signals, which, in conjunction with customer displays, the internet, cell phones, email, and text can alert customers and control devices (thermostats, smart appliances, water heaters) based on their demand response set-up. This use case also deals with the analytics around calculating the real-time energy information (usage, pricing, etc.) to participating customers to enable better demand decisions. The information can also be used in home or commercial/industrial building automation applications. In this case PSE&G would send dynamic pricing or device signals (perhaps real-time) to respond to a variety of drivers (CO2, feeder loading, major event, etc.) to request a customer's response or curtailment service. This use case is designed to contribute to energy, fossil fuel and carbon reductions.
2	2	**Asset Management & Health**	Using advanced asset analytics to enable smart asset management capabilities and become increasingly more focused on monitoring and predicting system health and deficiencies, and ensuring that all operations, investments and maintenance decisions are correct based on in-depth analysis and evaluation of detailed asset-level health and risk data. Being able to manage assets and integrated data (asset, condition, load, voltage, maintenance, etc.) in real time from a health and risk point of view is now a significant area of development in the industry.
2	3	**Reliability Analysis, Optimization, & Cost/Benefit**	Reliability analysis and optimization uses the network model, outage and iESP data to provide planning and upgrade advice to improve system reliability. It provides the ability to analyze outages over specified timeframes, jurisdictions, asset hierarchy (substation, main line conductor or trunk, switches, transformers, laterals, fuses, meter), and outage types, to review the impacts of outages on SAIDI, SAIFI, provide improvement options based on cost or risk, and cost benefit analysis.
2	4	**Distributed Generation Analysis**	Various technical and economic issues occur in the integration of distributed generation resources into a grid. Technical problems arise in the areas of power quality, voltage stability, harmonics, reliability, protection, and control, which require detailed analysis. This use case covers the establishment of the process, applications and analytics required to manage the behavior of network assets on the grid for all combinations of distributed energy generation locations. iESP level data is now critical to the effectiveness of this use case.
2	5	**System Planning Investment Portfolio**	System Planning & Investment are a core part of a utility's business and would be deployed in the planning and development of the distribution networks. This use case and its analytics would use iESP data with other information to cater for the growth in DER connections and help manage/optimize the capital investment program to ensure that the electricity networks remain fully compliant with the technical and regulatory requirements. The objectives here are to continuously improve the safety, security, reliability and capacity of the distribution networks, optimize the performance and condition of the existing assets, analyze the capability of the network to accommodate both demand and high volume of generation connections, provide innovative technical solutions, and produce analytic outputs (plans, cost/benefits) to support design and delivery teams and ensure the network is developed in the most economic, efficient and coordinated manner to meet customer requirements.
2	6	**Distribution Automation/ADMS**	The extension of intelligent monitoring and control over electrical power grid functions to the lowest network level (i.e., the iESP meter). The goal of Advanced Distribution Automation is real-time adjustment to changing loads, generation, and failure/outage conditions of the distribution system, usually without operator intervention. This necessitates control of field devices, which implies enough information technology (IT) development to enable automated decision making in the field and relaying of critical information to the utility control center. The IT infrastructure includes real-time data acquisition and communication with utility databases and other automated systems. Accurate modeling of distribution operations supports optimal decision making at the control center and in the field.
2	7	**Street-Lighting Remote Operations**	Use of the iESP Infrastructure to enable: - Remote control of lumens output of networked streetlights allows for the streetlight operators to remotely increase or decrease the lumens output of streetlights depending on various operational considerations. For example, perimeter lights around malls may be dimmed after hours to save energy and reduce light pollution complaints. Conversely, lights around stadiums or popular late night meeting spots may be increased / strobed to assist in crowd control. Motion activated perimeter lights may also provide a certain level of

Release #	Use Case #	Use Case Name	Use Case Overview
			deterrence against potential intrusions. - Remote monitoring of health leverages the communications capabilities of smart streetlights to allow operators to remotely determine the operating status of a particular streetlight without having to resort to either sending out night time patrol crews, or depending on customers to report particular outages.
2	8	**Customer Pre-Pay**	Customer service can use the ability of prepay programs to improve the customer choice and experience, and potentially assist deposit management. Prepay energy service allows consumers to pay in advance for utility services, to monitor their usage and account balance daily, and to manage their usage in a manner that is consistent with their household or property usage profile. Access to daily information can facilitate direct customer energy management. Pre-pay also allows customers the choice of when to consume in the case of transient properties – RV Parks, marinas, lake houses, etc... The spread of smart meters has resulted in opportunities for these new services.
2	9	**New Tariff Development**	Using customer segmentation, smart meter and market data - use pricing simulations to design and implement TOU rates that suit the regulated revenue frame, next generation and customer expectations. – Time-of-Use, Demand, DER specific pricing, market pass through, etc. This would also include support for new products and services and is heavily dependent on Customer Segmentation.
2	10	**Customer Smart Home/Appliances/Devices**	This Use Case relates to potential contribution of iESP data and infrastructure to support Home Energy Management Systems (HEMS) and more broadly the Smart Home. This objective is to utilize iESP meter data in combination with other behind the meter communications and smart devices - outlets, home Assistants (Alexa, Google Home, Home Pad), thermostats, appliances, etc., in combination with advanced analytics and visualizations that help the customer better engage with and manage their energy usage and other smart home functions (security, internet, etc..). The iESP network could be leveraged here as long as capacity and connectivity is available. in the event of a demand response request from the Utility, this would also include potential infrastructural support for optimal control/scheduling of DERs and automatic control of smart devices/appliances (thermostats, dishwasher/washing machines, water heaters, etc.)
2	11 & 12	**iESP Network & Data as a Service (aaS)**	This Use Case is intended to cover new business opportunities that could leverage the capabilities of the iESP data and infrastructure in an "as a service" mode to customers, other utilities, municipalities, communities or cities. Network as a Service – provision of the PSE&G iESP network capabilities to enable municipalities to connect their smart meters and provide smart services Data as a Service – provide iESP network and data services that mange both the smart meter device and meter data on behalf of the municipality.
2	13	**Critical Peak Pricing**	• Critical Peak Pricing: is a construct under which a utility can call a critical event when it anticipates or experiences high wholesale market prices or emergency system conditions and raise the rate. CPP rates can be fixed at a predetermined rate for each critical event or vary based on system demand during the critical event. CPP rates are designed to reduce a customer’s consumption on a limited number of days when critical events occur. • Critical Peak Rebates: these are offered when a utility calls a critical event during pre-specified time periods (e.g., 3 pm - 6 pm summer weekday afternoons) in response to anticipated or observed high wholesale market prices or emergency system conditions. The price for electricity remains the same during these periods but the customer is refunded at a single, predetermined value for any reduction in consumption as determined by the difference in what the utility deemed the customer was expected to consume and their actual consumption.
2	14	**Demand Response Control**	Demand Response Control is the automation of control functions that control DR mechanisms and devices in the field (with appropriate oversight). It is heavily dependent on the Demand Response Planning.
2	15	**Conservation Voltage Reduction/Optimization**	Conservation Voltage Regulation (CVR) is a technique for improving the efficiency of the electrical grid by reducing voltage on the feeder lines that run from substations to homes and businesses. CVR permanently lowers the voltage at which electrical power is delivered and yields an average of 0.6-0.8% energy savings for each 1% in voltage reduction down to 114V. AMI plays an important role in CVR by providing end-point voltage data (with certain customer meters set up as bellwether meters) to help analyze, lower and then monitor voltage levels on the circuit/feeder. With AMI in place CVR can be implemented with manual adjustments to tap changers, voltage regulators and capacitors. This would be enhanced by VVO but is not dependent on it. VVO is an extension of CVR in that it is the dynamic management of voltage and power quality. Where CVR is focused on conservation and involves permanent changes, VVO is focused on power quality, is far more dynamic in nature and can be supported by some level of distribution automation. VVO can also result in increases or decreases in voltage depending on the power quality issue. VVO can provide the monitoring and adjusting role for CVR and would allow a more aggressive reduction approach given some level of

Release #	Use Case #	Use Case Name	Use Case Overview
			automation. With new technology it is now far less expensive to save energy at the point of consumption, than it is to increase the capacity of the grid or create additional generation from power plants or DER.
3	1	**Smart Cities**	This Use Case is intended to cover the iESP data and infrastructure support contribution for any NJ or PSE&G Smart City initiatives, which have data and infrastructure needs and dependencies far broader that iESP. A smart city is an urban area that uses different types of electronic data collection sensors to supply information which is used to manage assets and resources efficiently. This includes data collected from citizens, devices, IoT, and assets that is processed and analyzed to monitor or manage traffic and transportation systems, environmental issues, power plants, water supply networks, waste management, law enforcement, information systems, schools, libraries, hospitals, parking, lighting, floods, and other community services.
3	2	**Microgrids**	This Use Case is intended to cover the iESP data and infrastructure support contribution for microgrid initiatives, which has data and infrastructure needs and dependencies far broader that iESP. A microgrid is a localized group of electricity sources and loads that normally operates connected to and synchronous with the traditional centralized electrical grid (macrogrid), but can also disconnect to "island mode" — and function autonomously as physical and/or economic conditions dictate.
3	3	**Innovative Products & Services**	The introduction of new and innovative products/services that are either new, or an improved version of current offerings. These new PSE&G products and services will leverage IESP data and network and look to deliver these in the key areas of Smart Customer, Home and City areas.
3	5	**Distribution/Bi-Directional Marketplaces**	Support of a transparent and unified distribution (or peer to peer) market for customers, DERs and other third-party products & services across the state that are animated and fully transactive. The extent to which PSE&G can use its iESP platform to support these new markets will largely depend on the strength of its foundational capabilities to better understand customers and communities.
3	4	**Customer Gamification & Loyalty Programs**	Customer side analytics and algorithms that use iESP and other market and household data to encourage education and gaming among customers. Analytics that assist in the design, management and evolution of customer loyalty programs (points, tiers, rewards)
3	6	**Asset Performance, Maintenance & Visualization**	Manufacturers' recommendations, models, estimates and visual inspection are typically used to determine when maintenance work should be done. However, it is not always known which assets are overloaded or often stressed on the distribution system. When iESP information is available and used to do asset loading analysis and other data analysis, work can be more accurately designed and scheduled. Predictive maintenance is a key component of a maintenance regime that involves using software for real-time monitoring of equipment health and comparing its current operational state to a model that defines normal or ideal operating conditions. Predictive analytics software uses advanced algorithms to detect subtle operational variances for each piece of equipment, which often warn of impending problems that might have gone unnoticed otherwise. Utilities can create automated alarm notifications and use the software to diagnose the source of equipment and system anomalies, in addition to prioritizing issues based on severity.
3	7	**Load Curtailment / Limiting**	An automated Load Curtailment Application detects predetermined trigger conditions in the network and performs predefined sets of control actions, such as opening or closing non-critical feeders, reconfiguring downstream transmission or sources of injections, or performing a tap control at a transformer. When a network is complex and covers a larger area, emergency actions taken downstream may reduce burden on upstream portions of the network. In a non-automated system, awareness and manual operator intervention play a key role in trouble mitigation. If the troubles are not addressed quickly enough, they can cascade exponentially and cause major catastrophic failure.
3	8	**Advanced (Automated) Outage Detection & Location**	Uses the network model, advanced algorithms, and fault signals, SCADA (sensor) and smart device measurements to automatically identify possible outage locations, network sections that are out and protection devices that operated. E.g. fuse blowout, recloser operation. Data is geospatially displayed in real-time, to allow fast response and crew dispatch to the precise location with information on the cause of the outage in order to restore power quickly. Automatically identify the number of customers affected by the outage, verify the outage/restoration by automated pinging devices and track the restoration in real-time. Improves response time to outages as well as proactively notifying customers through integration to other systems such as IVR, CIS, and OMS.
3	9	**Automated Fault Isolation & Restoration (FLISR) – Self Healing**	Isolates faults, perform automated switching actions to isolate faults and restore maximum number of customers. Ensures switching actions during restoration are safe and do not cause overloads or extreme voltage conditions in the system. Generates and displays ranked, ordered restoration, system restoration solutions, together with specific sequenced steps in real-time. Integrates DER and storage dispatch with system constraints, and safe

Release #	Use Case #	Use Case Name	Use Case Overview
			operations objectives, for a safer, more complete system restoration decision-making process. Allows for any combination of decentralized and centralized automation.
3	10	**Volt/VAR Control**	Volt/VAR Control or VVC refers to the process of managing voltage levels and reactive power throughout the power distribution system. Benefits: minimize feeder loss, maximize feeder power factor, minimize feeder voltage profile for variable consumption, and provide VAR support for transmission system. Volt/VAR application monitors system to determine if it's operating efficiently, and automatically operates field equipment to bring the system back into an optimized state if it goes out of the system parameters initially set by the operator.
3	11	**Customer Safety**	Assess reliability, service and safety impacts at a customer or meter/sensor level (gas leaks, flooding, CO2, etc.). Allows proactive identification of premise level reliability and safety concerns. Direct grid investments to customers with greatest outages. Cost effectively monitor reliability and safety goals. With iESP systems, Customer Service Representatives at the call center may be able to ping a customer's meter to determine whether or not it has voltage or there is any safety issue. This allows the representative to offer better advice on what to do in the current situation. iESP can sense and report issues when no one is present on premises. Utilities can use this information to notify customers of interruptions, in a manner of the customer's choice.
3	12	**Permanent Power Quality Management**	The purpose of the permanent power quality measurement enterprise activity is to provide long-term and continuous monitoring in order to provide reliability and benchmarking statistics. Many customers which can include utilities and large consumers of electric power have a need for an installed permanent power quality measurement system. Historically, power quality meters were portable and installed on a temporary basis in order to capture, diagnose and solve a specific problem that might be occurring in the facility. However, with increased demands for power quality and reliability benchmarking, power quality contracts, billing and energy use verification, predictive maintenance and others, the need and demand for permanent power quality monitoring has increased dramatically in recent years.
3	13	**Utility, Customer, & Community Energy Storage (Grid Level)**	Grid energy storage (also called large-scale energy storage) is a collection of methods used to store electrical energy on a large scale within an electrical power grid. Electrical energy is stored during times when production (especially from intermittent (utility and customer) power plants such as renewable electricity sources such as wind power, solar power) exceeds consumption, and returned to the grid when production falls below consumption. iESP data and sensors can be utilized to manage and optimize the bi-directional flows inherent with this DER technology.
3	14	**Asset Risk Analysis and Risk Scoring**	Risk Based Asset Management (RBAM) is an optimal maintenance business process used to examine energy network equipment such as feeders, poles, transformers, etc. It examines the health, safety and environment and business risk of 'active' and 'potential' damage mechanisms to assess and rank failure probability and consequence. This ranking is used to optimize inspection intervals based on site-acceptable risk levels and operating limits, while mitigating risks as appropriate. RBAM analysis can be qualitative, quantitative or semi-quantitative in nature and may also include financial or market risk variables. Smart devices across the network provide key data into the analytics of this process.
3	15	**Optimal Switch / Recloser Placement**	Optimal placement of protection devices and DERs in radial feeders is important to ensure power system reliability. This use case has specific algorithms that determine the optimal position of ACR's (individual or as part of an ASR scheme) on feeders on the network.
3	16	**Dynamic Circuit Reconfiguration**	In the use case, a fault occurs on the distribution system and the Fault Clearing Device clears the fault. The Fault Clearing Device sends the lock out signal to the Circuit Reconfiguration Controller (CRC). The CRC sends the lock out information to the Distribution SCADA (D-SCADA)/ Distribution Management System (DMS), the OMS, and Distribution Historian (SCADA history). The CRC sends an abnormal control area configuration status to any applicable Volt/VAR Controller. By polling the various smart devices, the CRC is able to perform a fault isolation calculation to isolate the fault. The CRC then sends a device command to the Isolation Device which acknowledges the command and performs the functions needed to isolate the fault. These events are monitored in the D-SCADA through regular polling of the devices. The CRC eventually calculates the reconfiguration scenario and sends the commands to the Reconfiguration Device which acknowledges the commands. After the Reconfiguration Device functions, it sends an update to the CRC which sends all equipment status updates to D-SCADA.
4	1	**Load Control, Adjustment, Optimization, & Contingency**	This Use Case places the "on-off switch" in the hands of the consumer using devices such as a smart grid controlled load control switch. While many residential consumers pay a flat rate for electricity year-round, the utility's costs actually vary constantly, depending on demand, the distribution network, and composition of the company's electricity portfolio. The application of load control technology continues to grow today with the sale of both radio frequency and powerline communication based systems. Certain types of smart meter systems can also serve as load control systems. Charge control systems can prevent the recharging of electric vehicles during peak hours. Vehicle-to-grid systems can return

Release #	Use Case #	Use Case Name	Use Case Overview
			electricity from an electric vehicle's batteries to the utility, or they can throttle the recharging of the vehicle batteries to a slower rate.
4	2	**Customer Building Automation Optimization**	Managing the energy and other needs in buildings efficiently and intelligently can have considerable benefits. A building energy management system (BEMS) is a sophisticated use case to monitor and control the building's energy needs. Next to energy management, the system can control and monitor a large variety of other aspects of the building regardless of whether it is residential or commercial. Examples of these functions are HVAC, lighting or security measures. BEMS technology can be applied in both residential and commercial buildings. The effectiveness of BEMS are greatly enhanced by the availability of smart devices and data at the building and equipment level and enable demand response and other energy efficiency capabilities
4	3	**Real-Time-Pricing**	The purpose of the Real-Time Pricing use case is to implement and manage a full scale distributed computing system that integrates key industry operations and permits customers to plan and modify their load and generation in response to price signals in “real-time” (operational timeframe which can range from seconds to days ahead), received from an energy services provider who acts as a facilitator and platform provider for the market.
4	4	**Storm/Lightning Analysis**	Leveraging investments in iESP Infrastructure that give utilities near-real-time readings on the health of their electric grid. The capability to use this and storm/lightning data in causal and predictive analysis can equip utility engineers and dispatchers to predict which assets will be affected by storms while optimizing the placement of crews, thus decreasing outage restoration times. Combined with geospatial visualization weather data and integrated statistical algorithms, the utility can be more prepared and shorten outages from weather events and identify weak points in the electrical distribution system thus preventing future outages.
4	5	**Vegetation Management**	"Predictive maintenance for trees". Factors such as annual growth rates, tree species, feeder construction type, and network configuration can be taken into account to achieve optimal reliability.
4	6	**Environmental / Sensitive Area Analysis**	Analytics that assist the mapping of environmentally sensitive areas (flora, fauna, etc.) in combination with iESP for other key planning functions (reliability, voltage, etc.)
4	7	**Storm Prediction**	See Storm Analysis - This Use case would operate in real time and allow pro-active planning of network and field resources, based on damage and outage assessments.
4	8	**Advanced DER Planning & Management (DERMs)**	The Advanced Distribution Automation System Function performs a) data gathering, along with data consistency checking and correcting; b) integrity checking of the distribution power system model; c) periodic and event-driven system modeling and analysis; d) current and predictive alarming; e) contingency analysis; f) coordinated Volt/VAR optimization: g) fault location, isolation, and service restoration; h) multi-level feeder reconfiguration; i) pre-arming of RAS and coordination of emergency actions in distribution; j) pre-arming of restoration schemes and coordination of restorative actions in distribution, and k) logging and reporting. These processes are performed through direct interfaces with different databases and systems, (EMS, OMS, CIS, MOS, SCADA, AM/FM/GIS, AMS and WMS), comprehensive near real-time simulations of operating conditions, near real-time predictive optimization, and actual real-time control of distribution operations.
4	9 & 10	**Control of DERs and HVAC Equipment** **DER Operations & Control**	The purpose of this Use Case is to stabilize power quality in a power distribution system with a large percentage of PV output. Commercial buildings with large demand can contribute to stabilize power quality by controlling demand of the building. Building energy management systems (BEMS) can control DERs and HVACs in response to DR signals from a utility EMS. There are three scenarios: 1) BEMS makes an operation schedule for DERs and HVAC equipment based on PV output prediction and building load prediction, 2) BEMS controls DERs and HVACs or building loads according to the operation schedule planned in Scenario 1, and 3) when BEMS receives a DR signal for islanding operation during DR mode in scenario 2, BEMS switches the system to islanding operation.
4	11	**Battery Aggregation & Control**	In a future where there is a high penetration of fluctuating energy sources, the demands on temporary storage will tend to become intensified. This use case describes interactions between the Grid operator, Grid EMS, Battery SCADA, Battery SCADA Operator and Stationary Batteries during online power system control for Battery Aggregation. Battery SCADA is used to control distributed Stationary Batteries as a Virtual Battery in two scenarios: for load frequency control by battery aggregation and for reserve margin by battery aggregation. This Use Case uses interoperable communications protocols to control all the aggregated storage units on the grid.
4	12	**PV/DER Output Forecasting/Backcasting**	This Use Case describes the sequence of activities required for forecasting generation and load by segment on the distribution system. An accurate load/generation forecast is essential for the operation of the system at high penetration levels. The DER forecast is based primarily on a detailed weather forecast, since weather influences both the loads and the generation. But typical weather regional forecasts do not meet the needs of predicting energy flows on discrete distribution line segments. It will be necessary to do microclimate forecasts for smaller zones within the region. Actual implementation of this Use Case's sequence may require multiple iterations in order for the system to converge on a solution,

Release #	Use Case #	Use Case Name	Use Case Overview
			at which point the DERC at the substation or lower level have some autonomy to maintain stability and respect the limits of the power system (i.e. they will have a pick list by resource by segment with weighting). This use case will calculate the output for various behind the meter DER sources (i.e. solar panel installation) for given project specific modelling parameters (i.e. panel orientation, power factor corrections) and weather data (i.e. solar irradiation or wind speed). This generation output data, in conjunction with iESP load data (net load data), can be used to determine the gross load on a particular feeder. Gross load data may be more helpful to plan for the worst case scenarios for contingency / planning purposes.
4	13	**Real-Reactive Load-Voltage Management**	This Use Case a) performs periodic and event-driven information exchanges between the EPS operator/DMS and microgrid operator/EMS about the aggregated reactive load and generation dependencies on voltage within the voltage ranges under normal operating conditions and b) provides the Electric Power System operator with relevant data for post-factum analyses, when needed. The information exchanges are performed through direct interfaces between DMS and EMS. Interfaces between the EMS and data aggregators may be used to meet the objective of the Function.
4	14	**Optimal Capacitor Bank Design & Placement**	Optimal location of Capacitor banks for deployment on the network to minimize voltage swells / sags. Optimization routine should be able to maximize cost/benefit, or other voltage stability metrics. The problem of Capacitor placement on a network system has a variety of complex multi-variable solution algorithms. The location, type, and size of capacitors, voltage constraints, and load variations are considered. The objective of Capacitor placement is peak power and energy loss reduction, taking into account the cost of the capacitors. The power flows in the system are explicitly represented, and the voltage constraints are incorporated. The master plan is used to determine the optimal location of the capacitors. Master plan sub-details lay out the type and size of the capacitors placed on the system.
4	15	**Switching Schedule & Safety Management**	A core function of a DMS has always been to support safe switching and work on the networks. Control engineers prepare switching schedules to isolate and make safe a section of network before work is carried out, and the DMS validates these schedules using its network model. Switching schedules can combine tele-controlled and manual (on-site) switching operations. When the required section has been made safe, the DMS allows a Permit to Work (PTW) document to be issued. After its cancellation when the work has been finished, the switching schedule then facilitates restoration of the normal running arrangements. Switching components can also be tagged to reflect any operational restrictions that are in force.
4	16	**Ancillary Services**	Market Operations Energy Services, for the purposes of this use case, collects bid and offers into the ancillary services market from Energy Service Providers and other aggregators of distributed ancillary resources. Market Operations evaluates incoming bids against needs and accepts or rejects those offers.
4	17	**Energy Management & Frequency Control**	This use case is a description of the information exchanges between a Data Acquisition subsystem and the load frequency control core of an Automatic Generation Control system. The calculation of economic dispatch and handling of generator schedules and production cost summaries form a separate use case [undocumented at present]. The AGC Load Frequency control subsystem receives new data values from the Data Acquisition subsystem (i.e. SCADA), calculates an Area Control Error and the required changes in generating unit set points. Set point controls are sent through the Data Acquisition subsystem to the power stations. The generating unit states can be made available for other applications.

Based on the above, a multiple year use case roadmap plan was developed to cover short-, medium- and long-term time horizons including the iESP deployment and beyond. A number of other factors were considered when moving from use case prioritization to the planning stage:

- Ability of iESP to support the use case date requirements
- Mandatory dependencies
- Use case inventory and current status of Use Cases
- Availability of quality data from reliable sources
- Functional and data affinity across use cases
- Current commitments, plans and budgets
- Capacity of PSE&G to take on use case development projects
- Organizational impact – process, people
- Technology impact – databases, communications, security

Deployment of the use case capabilities will take place in a managed (POC -> Pilot -> Production) Agile manner according to the program roadmap and PSE&G capability. As such, some use cases will be deployed in parallel while others might jump forward on the roadmap based on any changing priorities.

Figure 4-3: PSE&G Use Case Roadmap

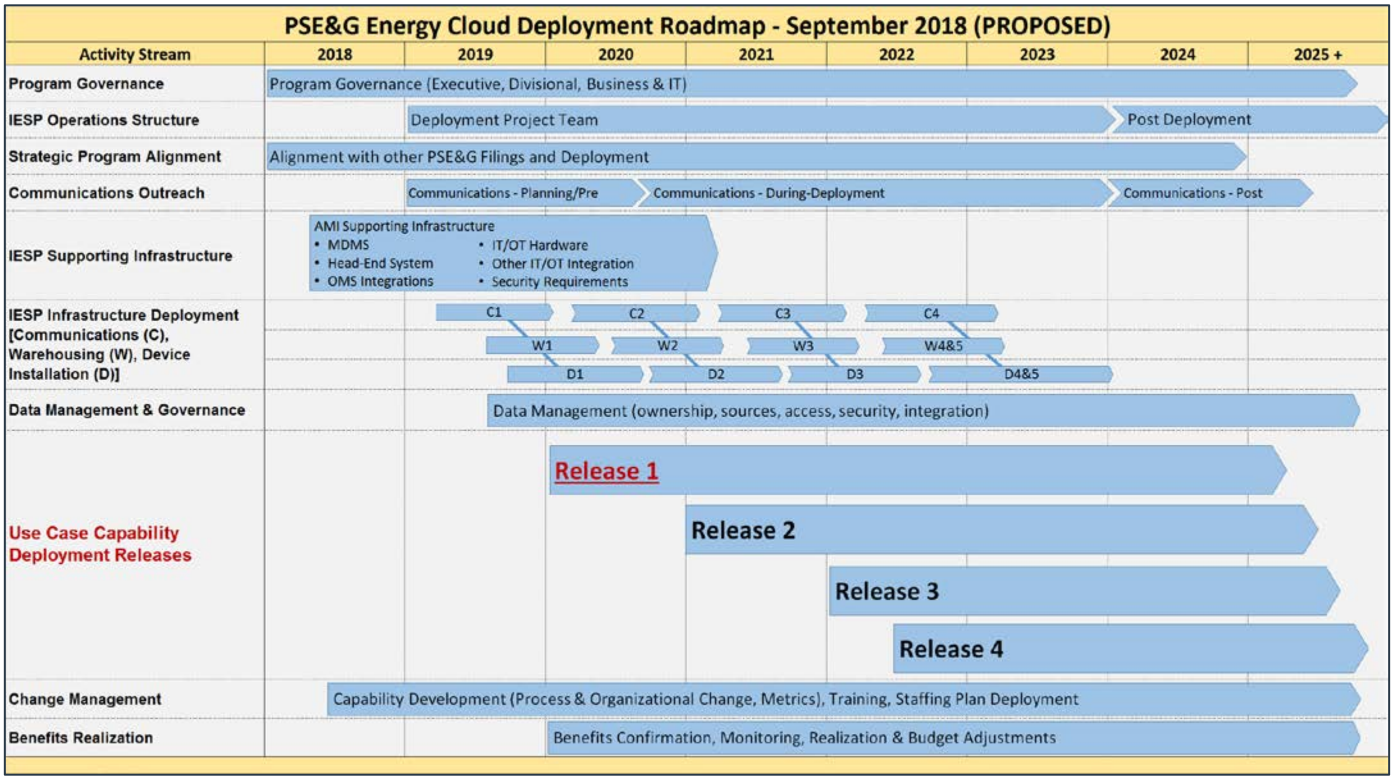
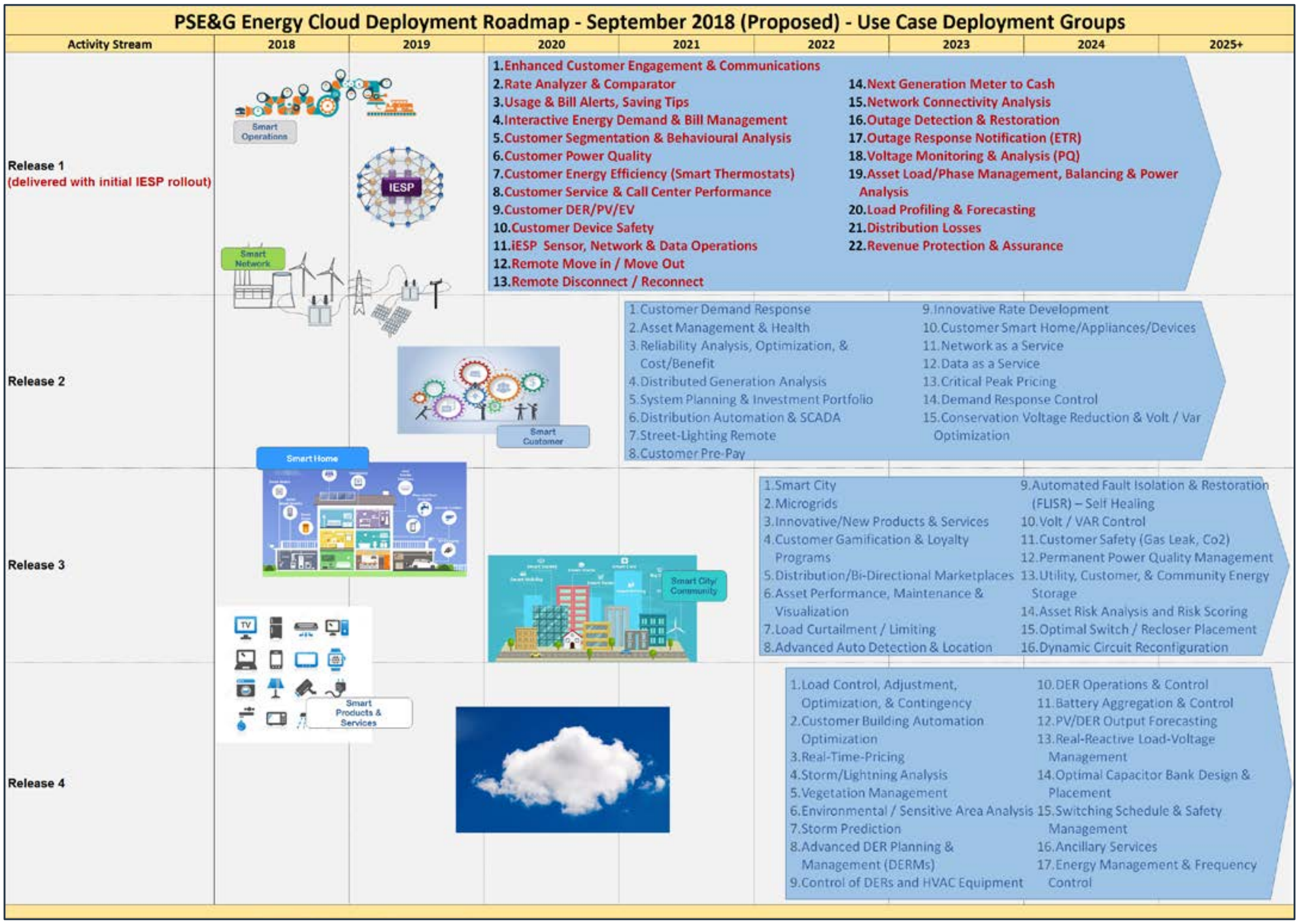


Figure 4-4: Deployment Plan Use Case Groups



4.2 DEPLOYMENT PLAN OPTIONS AND CONSIDERATIONS

The following figures show the proposed iESP implementation deployment plan based on the roadmap above. It provides more detail and breaks down on the key activities and dependencies inherent in the roadmap.

Figure 4-5: Deployment Plan Overview

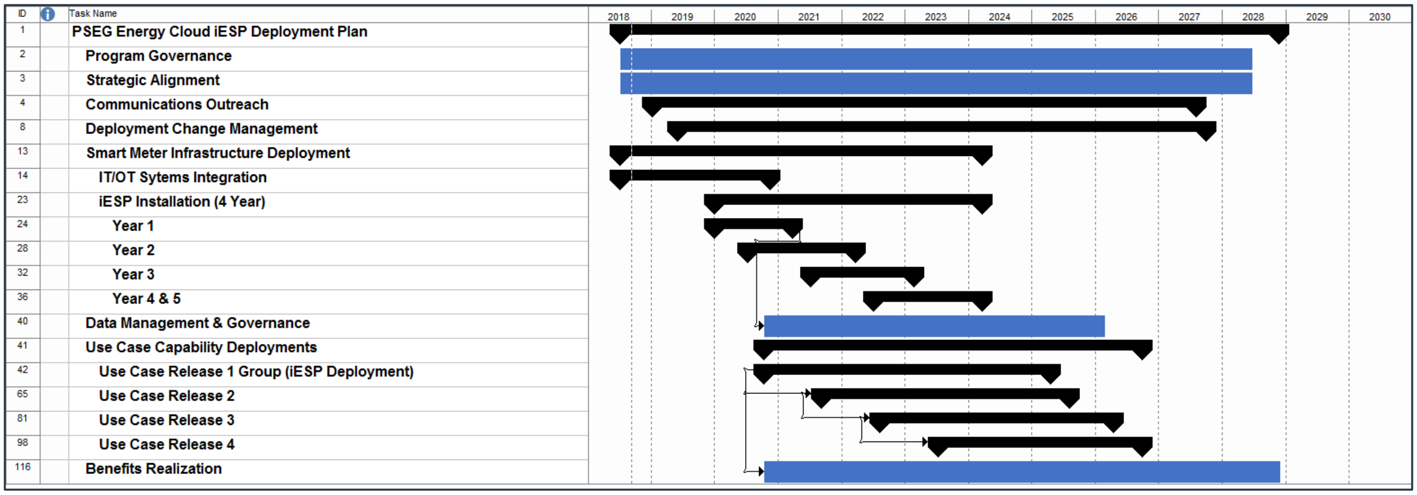


Figure 4-6: iESP and Use Case Deployment Plan (1 of 3)

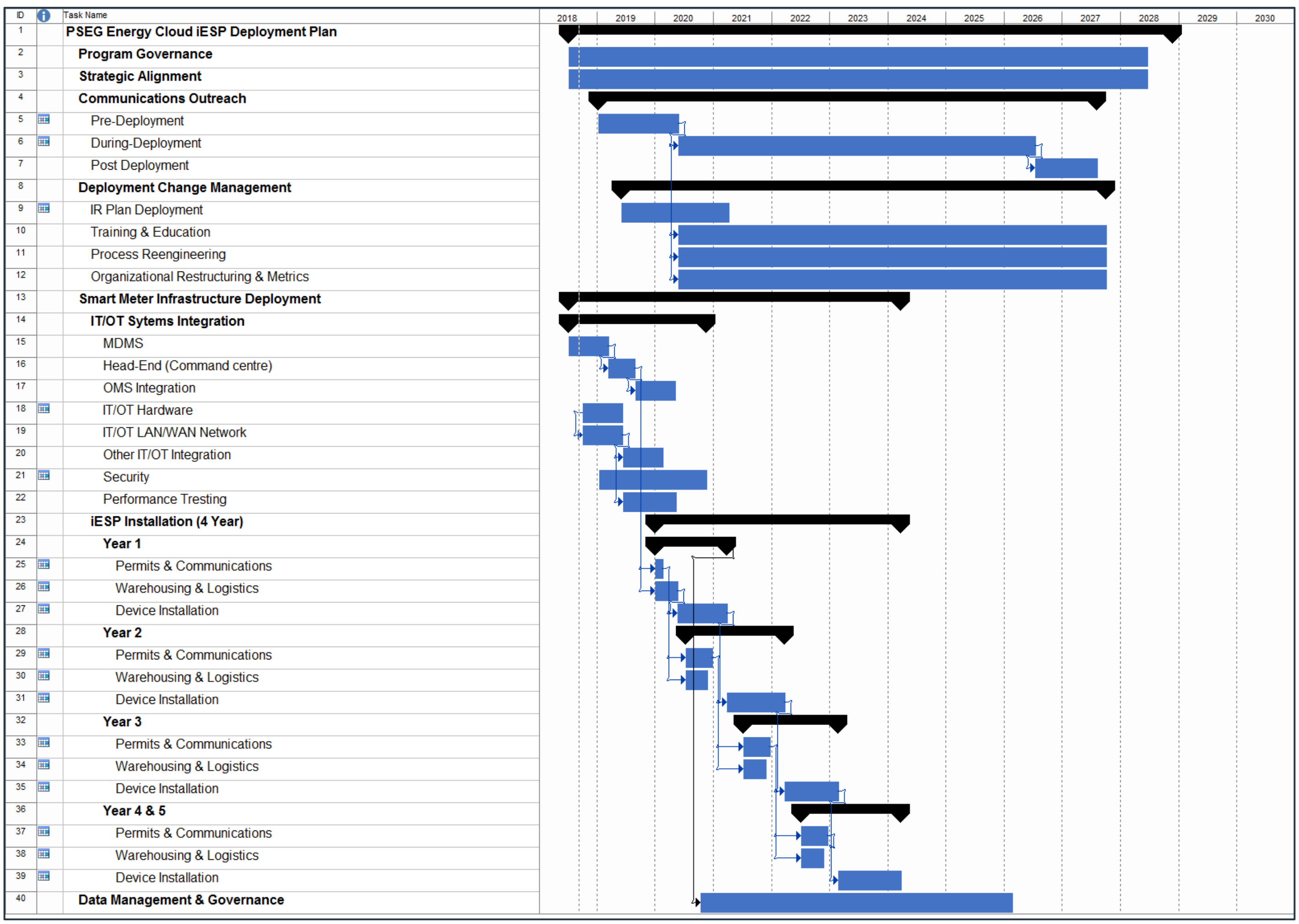


Figure 4-7: iESP and Use Case Deployment Plan (2 of 3)

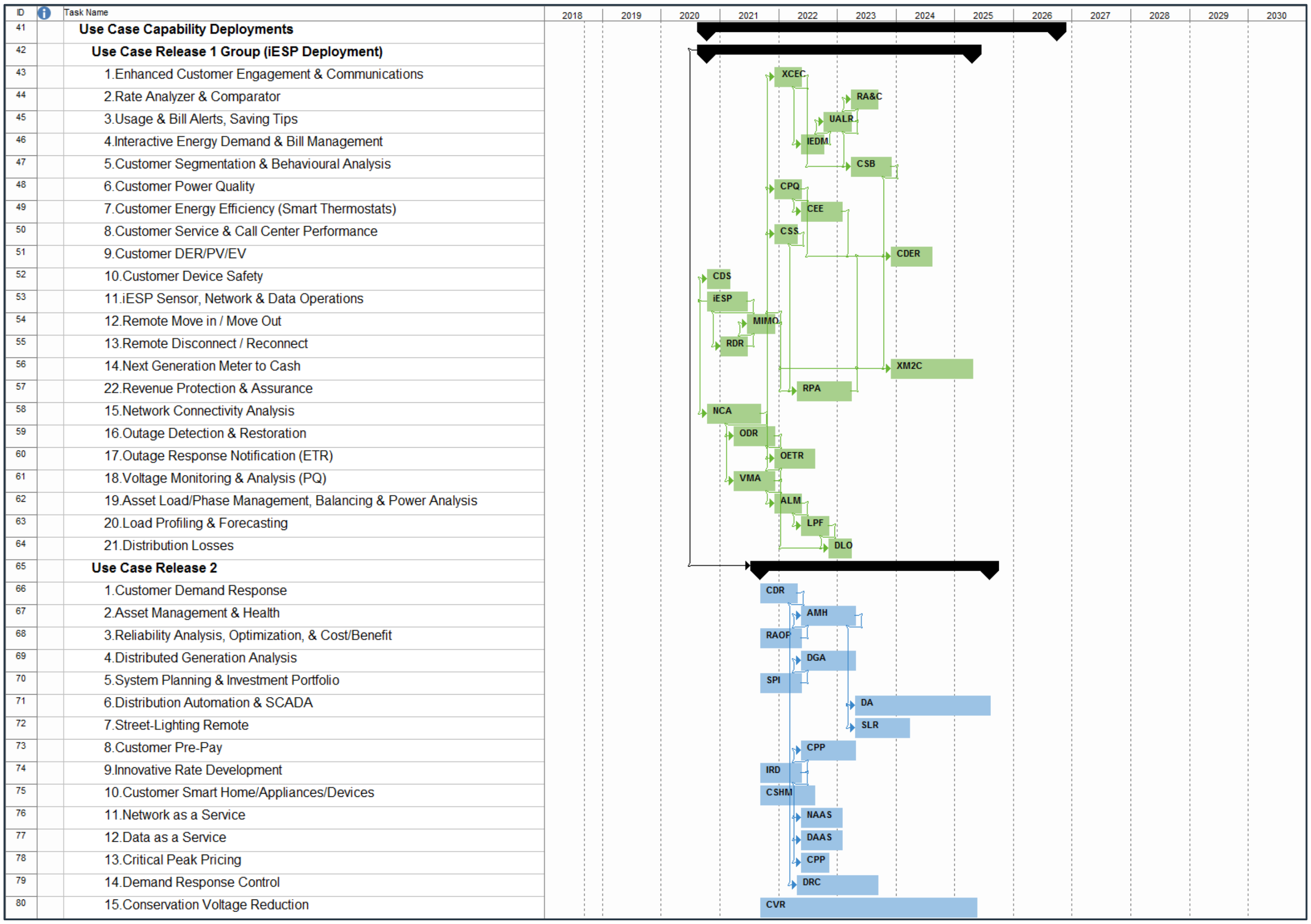
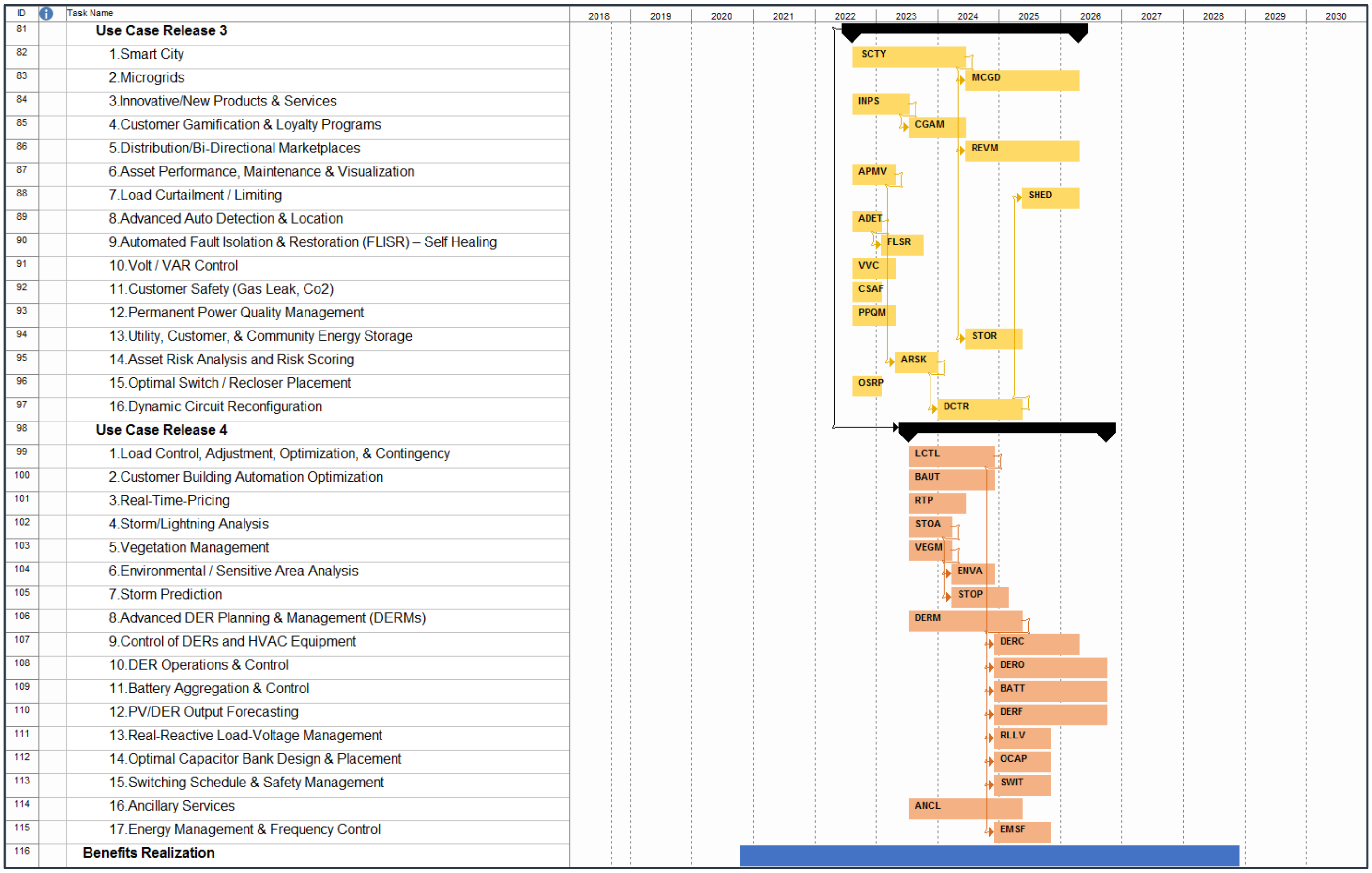


Figure 4-8: iESP and Use Case Deployment Plan (3 of 3)



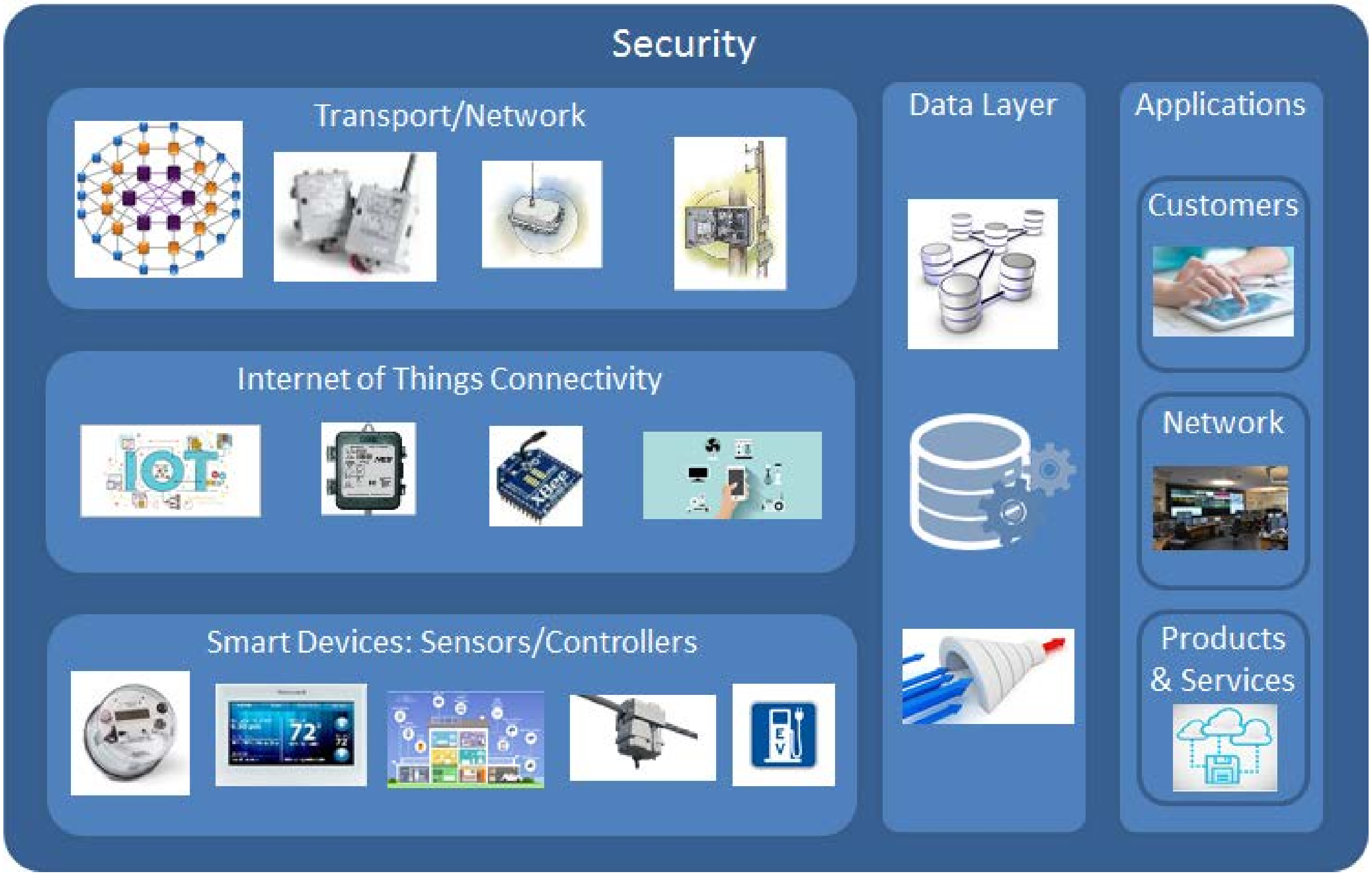
4.2.1 PSE&G Energy Cloud Technology Architecture Implications & Enabling Capabilities

From a technology architecture point of view the deployment of the PSE&G Cloud, its supporting iESP devices, infrastructure, and the availability of significantly larger and more granular volumes of quality network and customer data, will result in impacts across the application, data, infrastructure and security architectures. These impacts will be further increased by the drive to real-time operations in both grid and customers areas. This section provides a high-level view of the potential application (and integration) architecture future state impacts in regards to leveraging the Energy Cloud infrastructure to enable “Smart” capabilities, and the expected security specifications required for iESP.

PSE&G Energy Cloud Overall Technology Architecture

The following diagram illustrates the overall layered technology architecture that will evolve as part of PSE&G’s Energy Cloud deployment program. This program will obviously rely heavily on technology infrastructure to enable the business and customer use cases on the roadmap. At its core will be the iESP, which is comprised of the infrastructure on which the PSE&G Energy Cloud operates. As illustrated below, the iESP includes a two-way communications network layer, a layer to collect and analyze operational and customer data, an IoT platform, and an application runtime in which multiple services and applications are developed. The iESP will also include all necessary cyber security components to ensure information protection and operational continuity.

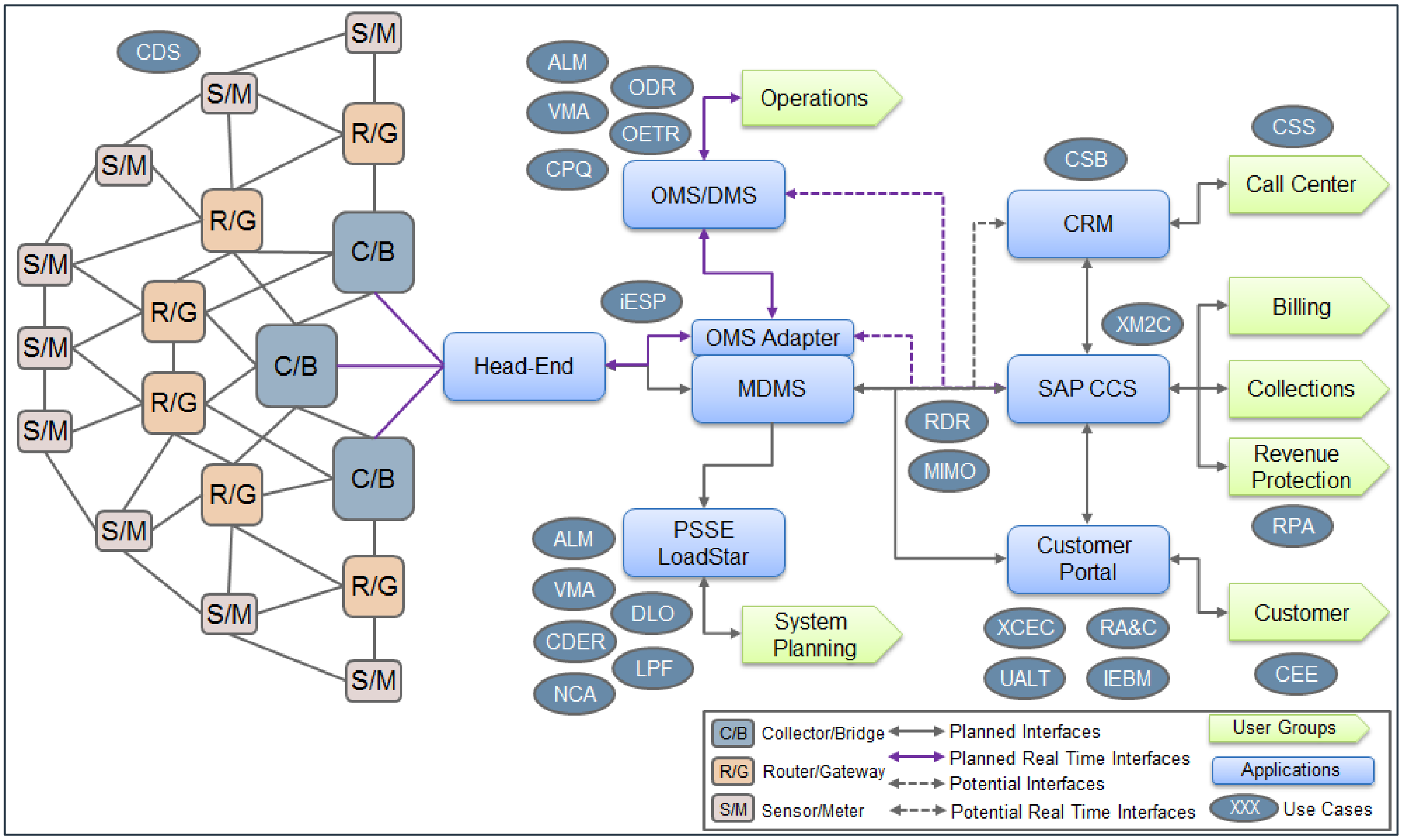
Figure 4-9: PSE&G iESP High-Level Application Architecture: Layers



PSE&G iESP High Level Application Architecture & Release 1 Use Cases

The following provides the high-level view of the core iESP application and integration architecture. The release 1 use cases are mapped to indicate where their deployment will primarily have impact. Potential real-time flows are also highlighted.

Figure 4-10: PSE&G iESP High-Level Application Architecture & Release 1 Use Cases



Release 1 Use Cases			
Enhanced Customer Engagement & Communications	XCEC	Remote Move in / Move Out	MIMO
Rate Analyzer & Comparator	RA&C	Remote Disconnect / Reconnect	RDR
Usage & Bill Alerts, Saving Tips	UALR	Next Generation Meter-to-Cash	XM2C
Interactive Energy Demand & Bill Management	IEDM	Network Connectivity Analysis	NCA
Customer Segmentation & Behavioral Analysis	CSB	Outage Detection & Restoration	ODR
Customer Power Quality	CPQ	Outage Response Notification (ETR)	OETR
Customer Energy Efficiency	CEE	Voltage Monitoring & Analysis (PQ)	VMA
Customer Service & Call Center Performance	CSS	Asset Load/Phase Management, Balancing & Power Analysis	ALM
Customer DER/PV/EV	CDER	Load Profiling & Forecasting	LPF
Customer Device Safety	CDS	Distribution Losses	DLO
iESP Sensor, Network & Data Operations	iESP	Revenue Protection & Assurance	RPA

PSE&G iESP High Level Technical Architecture

Figure 4-11: PSE&G iESP High-Level Application Architecture – Network & Data Interfaces

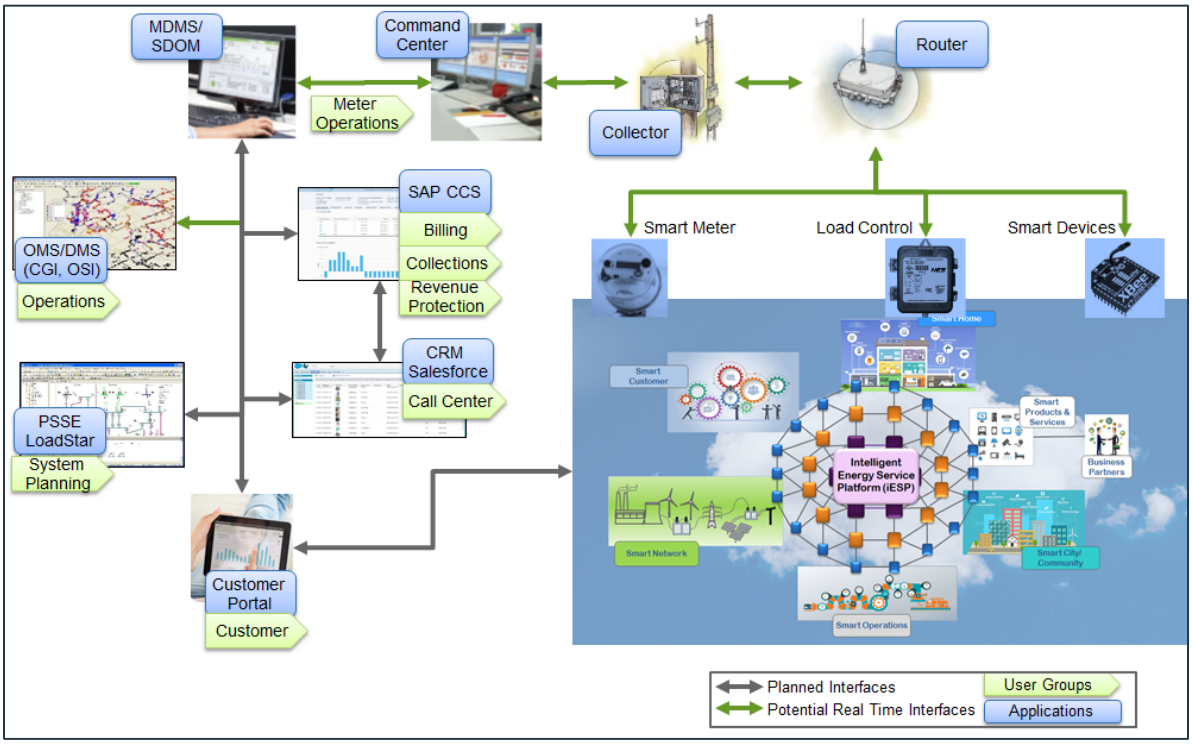


Figure 4-12: PSE&G iESP High-Level Application Architecture – Device Specifications

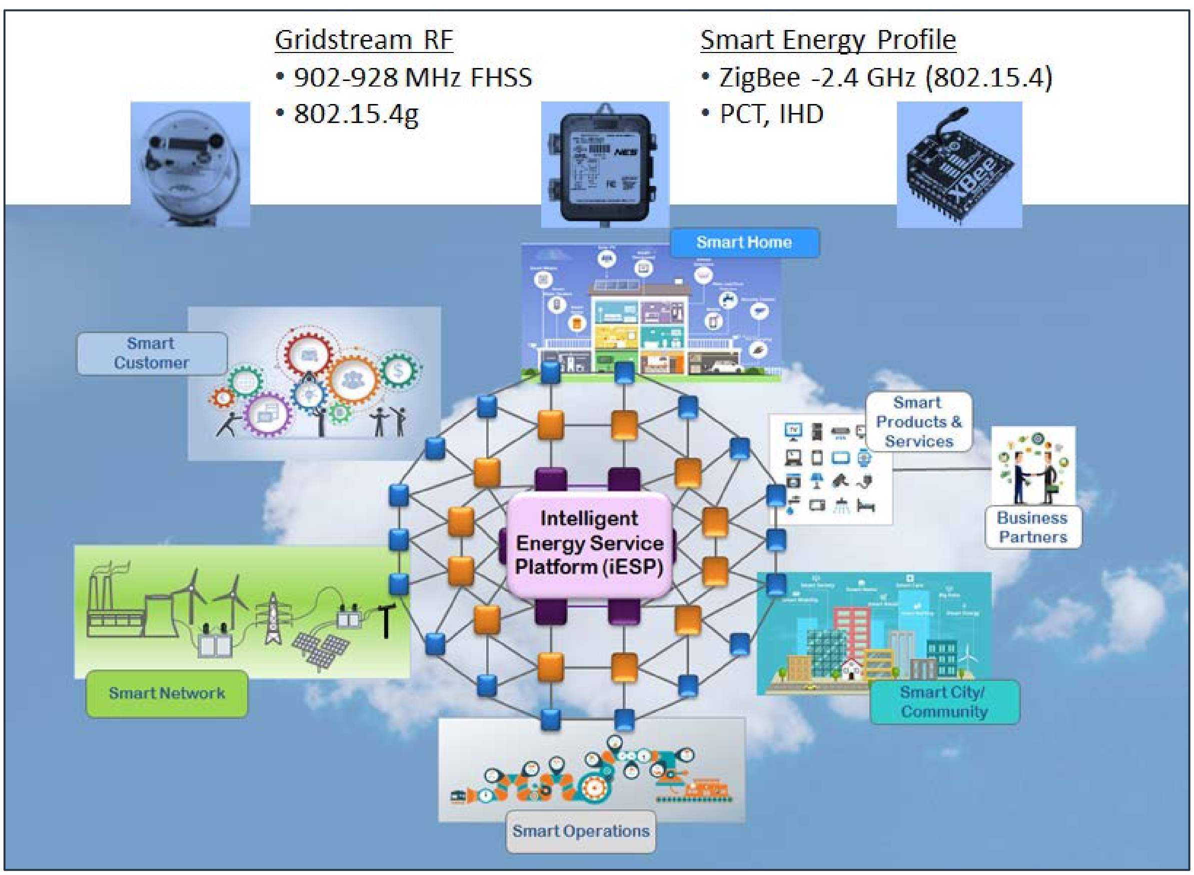


Figure 4-13: PSE&G iESP High-Level Application Architecture – Communications & Data Management

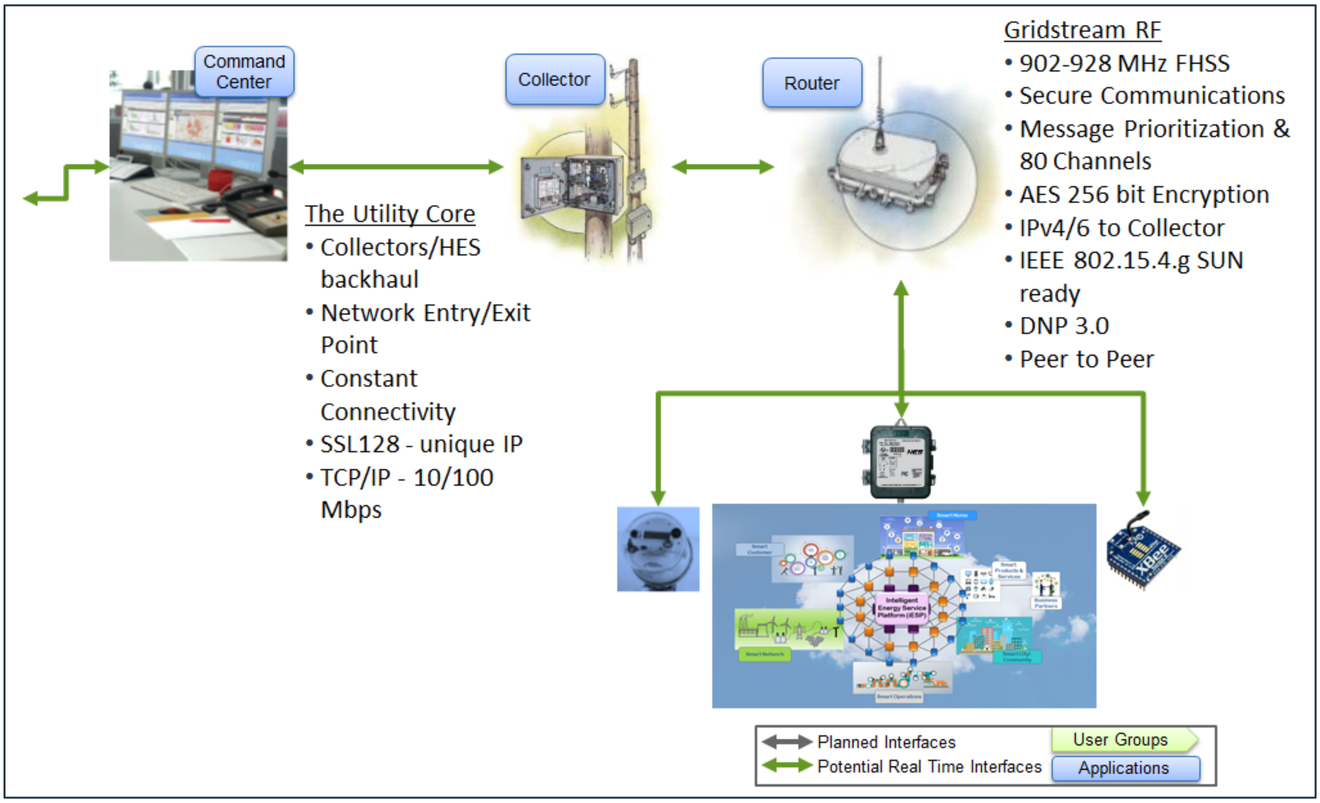
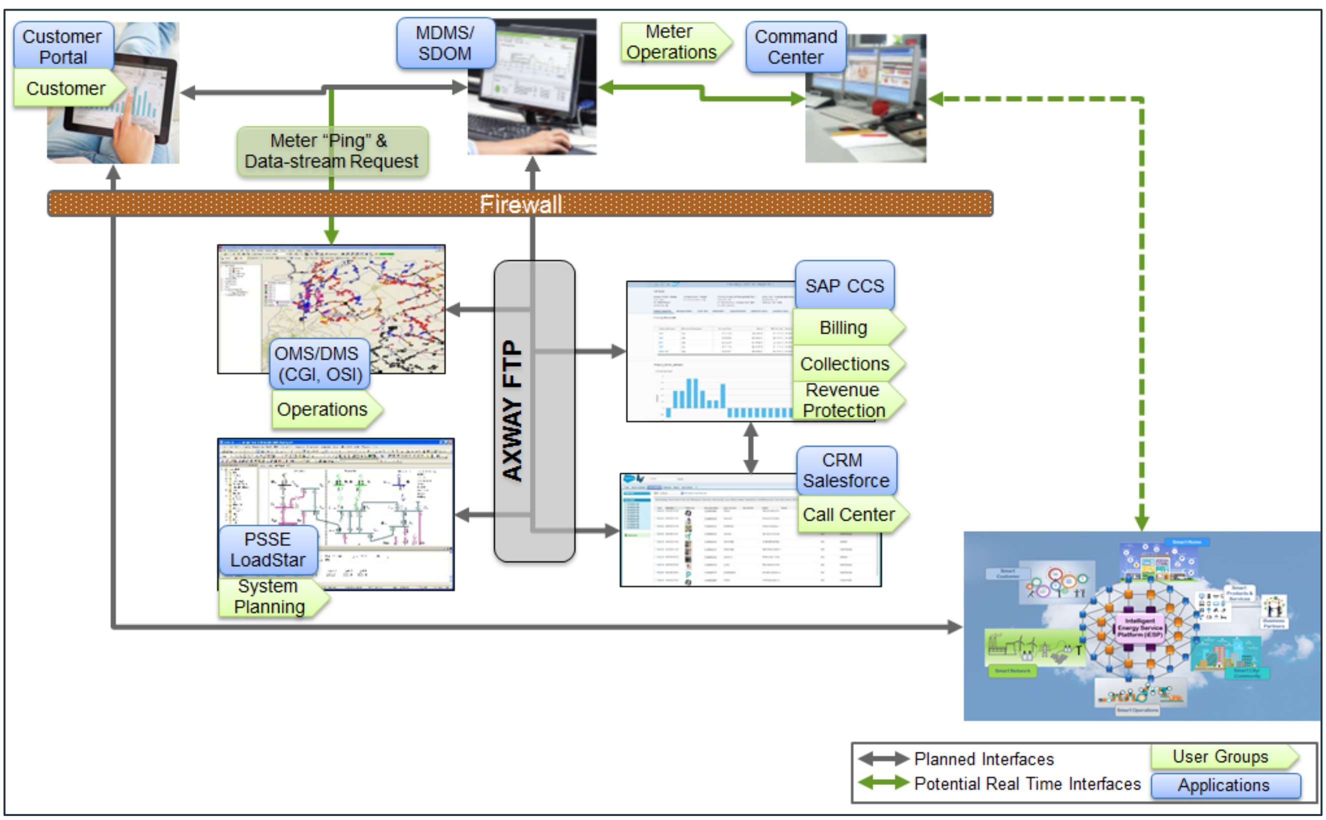


Figure 4-14: PSE&G iESP High-Level Application Architecture – Data & Security Integration



iESP Communications Architecture & the Smart Home – iESP Network as a Service

It is technically feasible to utilize the PSE&G Energy Cloud, the iESP communications network and applications to facilitate any future Smart Home capabilities. The capacity to support this sort of functionality will depend on the amount of bandwidth required and the amount being utilized by core iESP operations and Use Cases.

There are two paths for integration with appliances using Landis+Gyr (L+G) technology, Zigbee and the L+G single board network radio. The L+G single board radio is a small form factor network adapter that can be integrated into customer appliances allowing signals and controls to be issued to the appliance. Current use cases that have been implemented include thermostats, hot water heaters, pool pumps, heaters. Additional use cases can be developed in partnership with appliance manufacturers and others.

L+G devices equipped with Zigbee have the ability to integrate with in home devices. Smart appliances and other devices can pair with the device to receive information and controls sent via the iESP network using the device as a communication hub for devices inside the home. Some appliance manufacturers have begun integrating Zigbee into their appliances. Appliances such as washing machines, clothes dryers, dishwashers can receive signals sent via the network to control activities. Load management, for instance, can be orchestrated to defer the use of high-energy consuming appliances during peak load periods to help the utility manage these loads, and depending upon the tariffs in place, help the customer save money during peak load periods.

Additional use cases for each path can also include controlling and managing in-home solar, energy storage (batteries), as well as charging stations for electric vehicles.

Note: The Zigbee alliance is a consortium of vendors working together to help ensure standardization and develop uses of smart appliances in the home. Please see the link for additional information:

http://www.zigbee.org/zigbee-for-developers/applicationstandards/zigbeehomeautomation/

iESP Communications Security Specifications

As with all previous initiatives, PSE&G has established reasonable security guidelines and data protection procedures with respect to customer data, and in coordination with the requirements established by the National Institute of Standards and Technology (NIST). NIST is a governmental agency that defines Federal Information Processing Standards (FIPS).

In addition, the designed iESP network will follow the below cyber security requirements:

- **Device Specific Encryption Keys:** Each device is provisioned with unique encryption keys used to protect the privacy and integrity of data and commands sent to and from the device.
- **Secure Command Broadcast:** Commands broadcasted to groups of devices are also secured with unique encryption keys that provide confidentiality, integrity, and authentication for the command.
- **Downstream Message Authentication**: Verify messages using a digital signature to ensure commands originated from a trusted source.
- **Bi-Directional Message Integrity**: Validate two-way network messages using unique encryption keys to create hashed message authentication codes to support message integrity.
- **Mutual Authentication**: Authenticate upstream and downstream messages and check for integrity in the receiving device.
- **Field Tool Authentication**: Authenticate and secure communication between devices in the field and the field tools.
- **Certified Root of Trust**: Store and maintain a Utility Signing Key within certified security appliances in a high-availability environment.

4.3 ADDRESSING THE IMPACTS TO PSE&G EMPLOYEES OF DEPLOYING IESP

The PSE&G Energy Cloud deployment will significantly reduce the number of personnel required to support meter device reading. Smart devices installed as part of the iESP will obviate the need for Meter Readers in the field and management and support personnel positions will be displaced by the PSE&G Energy Cloud rollout. The company has identified ample opportunities for these displaced employees to transition to new roles as entry-level and management positions and open due to normal attrition through 2025. Based on historical averages, 236 open positions are anticipated in 2019 and 197 positions, on average, from 2020-2025 in Gas Operations, Electric Operations and Customer Operations that displaced employees can fill.

05

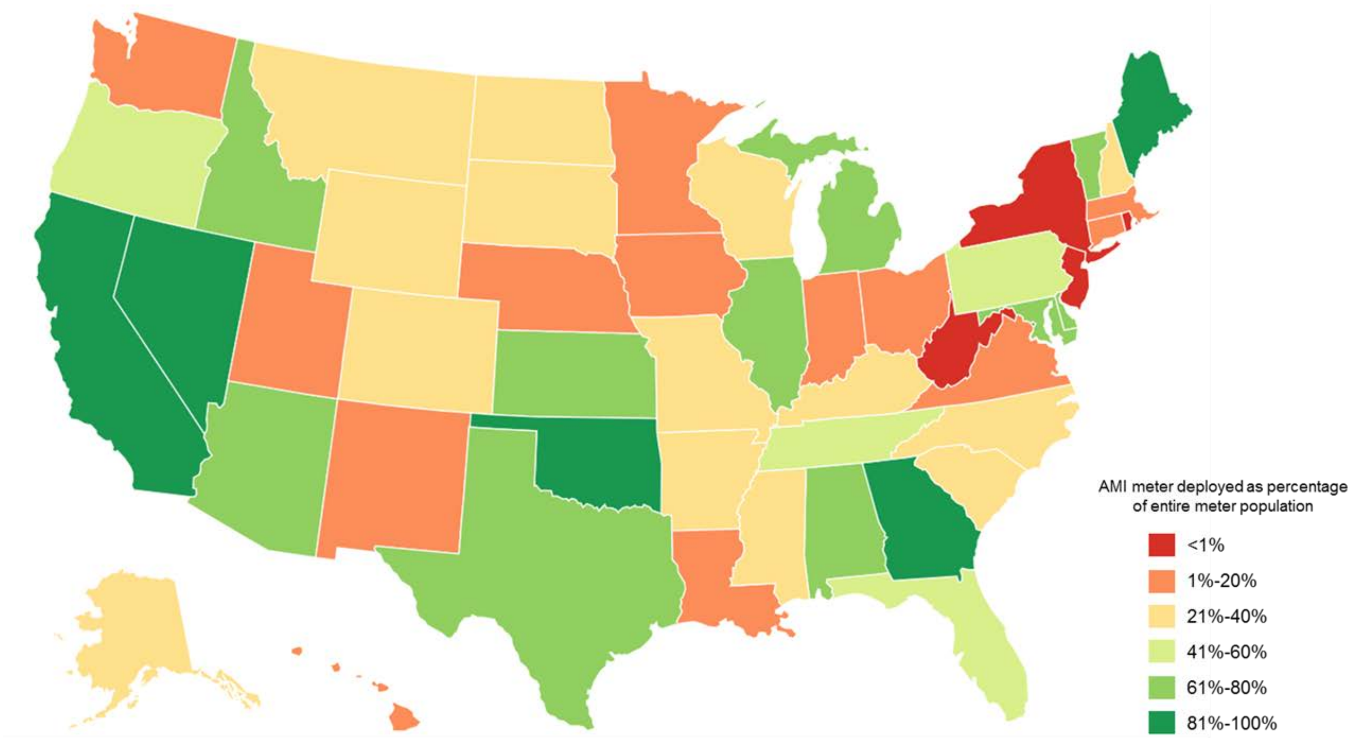
APPENDIX

5 APPENDIX

5.1 SMART DEVICE OVERVIEW

According to the United States EIA, as of December 2016, more than 71 million smart meters were deployed in the United States, covering 47% of the 150 million electricity customers in the U.S. The figure below shows the extent of smart device deployments by state that were completed through 2016. Smart device penetration rates vary widely by state. Washington, D.C., has the highest smart meter penetration rate at 97%, followed by Nevada at 96%. In 2016, six other states had a residential smart meter penetration rate higher than 80%: Maine, Georgia, Michigan, Oklahoma, California, and Vermont. In 2016, Texas added the most residential smart meters of any state, installing smart devices on more than 200,000 customer accounts. At year-end 2016, New Jersey was ranked the 47th U.S. state in terms of smart meter penetration. Year-end 2017 smart device deployment data is not publicly available through EIA until 4th quarter of 2018. Consolidated Edison (ConEd) was approved in March 2017 to deploy ~3 million smart meters over the next five years.

Figure 5-1: Smart Meter Adoption Rate by State, year-end 2016[8]



[8] "NEARLY HALF OF ALL U.S. ELECTRICITY CUSTOMERS HAVE SMART DEVICES," UNITED STATES ENERGY INFORMATION ADMINISTRATION, DECEMBER 2017; HTTPS://WWW.EIA.GOV/TODAYINENERGY/DETAIL.PHP?ID=34012

5.2 FINANCIAL BENEFITS

Both benefits and costs come from a broad range of use cases, the net effect of which is a business case that is comfortably economically viable and carries less risk when considering customer and operational benefits over the 20-year horizon, as shown below.

5.2.1 Business Case Overview

Figure 5-2: Cost-Benefit Analysis Overview

Business Case Overview $M		
Benefits	**Nominal Value**	**Present Value***
1. Operational Benefits	$887	$384
2. Customer Benefits	$843	$372
3. Total Benefits (1 + 2)	**$1,730**	**$756**
Costs		
4. O&M Costs	($73)	($56)
5. Capital Costs	($721)	($553)
6. Total Costs (4 + 5)	**($794)**	**($609)**
Net Benefits		
7. Net Benefit (3 – 6)	**$937**	**$147**

Benefits Overview $M		
Operational Benefits	**Nominal Value**	**Present Value***
Customer Operations	$567	$245
Grid Operations - Gas	$196	$85
Grid Operations – Electric	$124	$54
Total Operational Benefits	**$887**	**$384**
Customer Benefits		
Time of use rates	$38	$16
Better storm outage response	$38	$17
Reduction in usage related to inactive accounts	$266	$118
Reduction in write-off	$353	$153
Avoided theft	$138	$62
Recovery of line loss attributed to slow meters	$11	$5
Future Capabilities	Individual Cases	
Total Customer Benefits	**$843**	**$372**
Total Benefits	**$1,730**	**$756**

* Present value is based on pre-tax cash flows at 6.85% discount rate per PSE&G 12+0 rate case filing.

5.2.2 Cost and Benefits Definition

Base Costs

Figure 5-3: PSE&G Energy Cloud Capital & O&M Costs

Item	Overview/Assumptions	Estimated Costs ($m) (2.5% CPI)
Meter Material	Cost of 2.3M electric meters	$320.6
Meter Installation	Installation of 2.3M electric meters	$199.7
Project Management	Core Project Team staff	$37.8
Meter Security Material	Barrel lock key, barrel locks, seals, caps, fort Knox:	$23.9
Customer Communication	Customer outreach and marketing for Meter deployment and other AMI benefits	$42.9
Meter Testing	Cost to test 2.3m removed electric meters:	$16.7
IT Support	CRM/Salesforce, disconnect/reconnect, workflows (volume test), integrate w/MDT's, network - expansion, security, testing penetration	$22.5
Warehouse Equipment and Labor	Test boards, fork lifts, pallet jacks, dumpsters, meter tech labor, communication with PSE&G systems	$13.0
Network Expansion	Pole purchase and installation, router Installation, data collector, installation, utility technology labor, customer operations labor, network vendor	$15.8
Vendor Labor (L+G)	Vendor project staff. Pricing needs to be formalized with extension to Econet contract	$9.9
Warehouse Lease	Warehouse leasing to store meters	$15.0
AMI Consultants	Project AMI consulting as needed	$7.5
Additional Staffing: Call Center	Additional Service Representations to handle high than normal call volume	$7.4
Additional support for Use Cases	Additional support for use cases	$15.0
Additional Staffing: System Integration	Additional Data Administrators to work closely with AMI team and L+G resolving network communication issues	$7.4
Additional Staffing: Billing	Additional Bookkeepers to resolve high than normal billing irregularities	$7.4
Additional Staffing: OSG	Additional Analysts to work closely with AMI team modifying Meter Readers books	$7.4
Meter Site Repairs	Meter site repairs: meter pan, jaws	$7.5
Training	Staff Training & Upskilling	$7.5
Automate Manual Processes	Billing and system integration processes	$7.5
Outside Counsel	Support of outside counsel to negotiate contracts	$1.5
Total		**$793.8**

Additional Costs Definition

Figure 5-4: Additional PSE&G Energy Cloud Costs related to use case deployment

Benefit	Overview/Assumptions		O&M	Capital
Customer Engagement Portal/EMS	O&M: Estimated O&M costs for additional use case capabilities over and above costs already in the Business Case. Cost estimates cover activities including process reengineering, business model changes, training and people development activities.	CAPITAL: Estimated Capital costs for additional use case capabilities over and above costs already in the Business Case. Cost estimates cover activities including: Software, Hardware, Integration, Configuration, Data Migration & Cleansing.	$826,113	$340,164
Customer Segmentation & Behavioral Analysis			$219,825	$366,375
Customer Power Quality			$214,464	$357,439
Customer Energy Efficiency Programs			$280,845	$561,691
Customer Service & Call Center Performance			$393,373	$353,027
Customer DER/PV/EV & Charging Stations			$361,963	$537,773
Smart Meter Network, Operations, & MDM			$258,411	$268,349
Customer Move-in/Move Out, Remote Disconnect/Re-Connect			$344,416	$688,832
Meter to Cash			$250,605	$651,574
Network Connectivity Analysis			$336,269	$267,037
Outage Detection/Response			$812,024	$659,769
Outage Response ETR			$60,145	$150,363
Voltage Monitoring & Analysis (PQ)			$211,293	$352,155
Conservation Voltage Reduction			$571,472	$339,968
Asset Load/Phase Management, Balancing & Power Analysis (incl. TLM)			$370,429	$507,437
Load Profiling & Forecasting			$265,526	$229,783
Distribution Losses			$219,858	$366,431
Revenue Protection & Assurance			$529,742	$275,058
Total			**$6,526,773**	**$7,273,227**

Operational Benefits

Figure 5-5: PSE&G Energy Cloud Business Case Operational Benefits

Benefit	Overview/Assumptions	20 Year Benefit (2.5% CPI)
Reduction of Meter Reading workforce and closure of leased facilities	Cost reduction due to automated meter reading: electric (iESP) and gas AMR	$506,740,132
Reduction of Billing workforce	Cost reduction due to a decline of billing irregularities	$31,524,839
Reduction of Call Center workforce	Cost reduction due to a decline in customer phone calls	$21,153,407
Reduction of Backoffice Collection workforce	Cost reduction due to a decline of backoffice collection workload	$3,259,313
Reduction of Revenue Integrity workforce	Cost reduction due to improved leads resulting in increased field time and less off time for RID investigators	$2,034,036
Reduction of Electric workforce	Cost reduction due to remote turn-on/off of electric meters. MIMO and Collection activity automated.	$38,417,912
Reduction of Gas workforce	Cost reduction due to remote turn-on/off of electric meters and gas AMR reads. MIMO and Collection activity automated.	$139,333,786
Reduction in truck rolls related to MIMO/Remote Disconnect/Remote Reconnect (Electric, Gas & Fleet)	Cost reduction due to avoided truck roll costs (excluding productive and non-productive labor) included for Move in move outs & Turn on turn offs	$83,448,498
Cut at pole/Cut at manhole	Cost reduction due to avoided truck roll costs (including productive and non-productive labor) included for cut at pole/cut at manhole type events	$26,342,144
Customer side issues	Cost reduction due to avoided truck roll costs (including productive and non-productive labor) included for avoidance of customer side issues	$20,221,710
Power Quality (transformer trips)	Cost reduction due to avoided truck roll costs (including productive and non-productive labor) included for transformer type events	$807,662
Avoided truck rolls for meter changes related to changed rate orders	Cost reduction due to avoided truck roll costs (including productive and non-productive labor) included for meter changes related to changed rate orders	$8,251,168
Reduced truck rolls related in lieu of outage call backs (complete on arrival- storm related)	Cost reduction due to avoided truck roll costs (including productive and non-productive labor) conducted in lieu of outage callbacks. Leveraging detailed nested outage information.	$3,601,952
Reduction in OMS calls at call center	Reduction in OMS related calls at call center due to improved outage information and increased pro-active communications.	$2,047,621
Total		**$887,184,180**

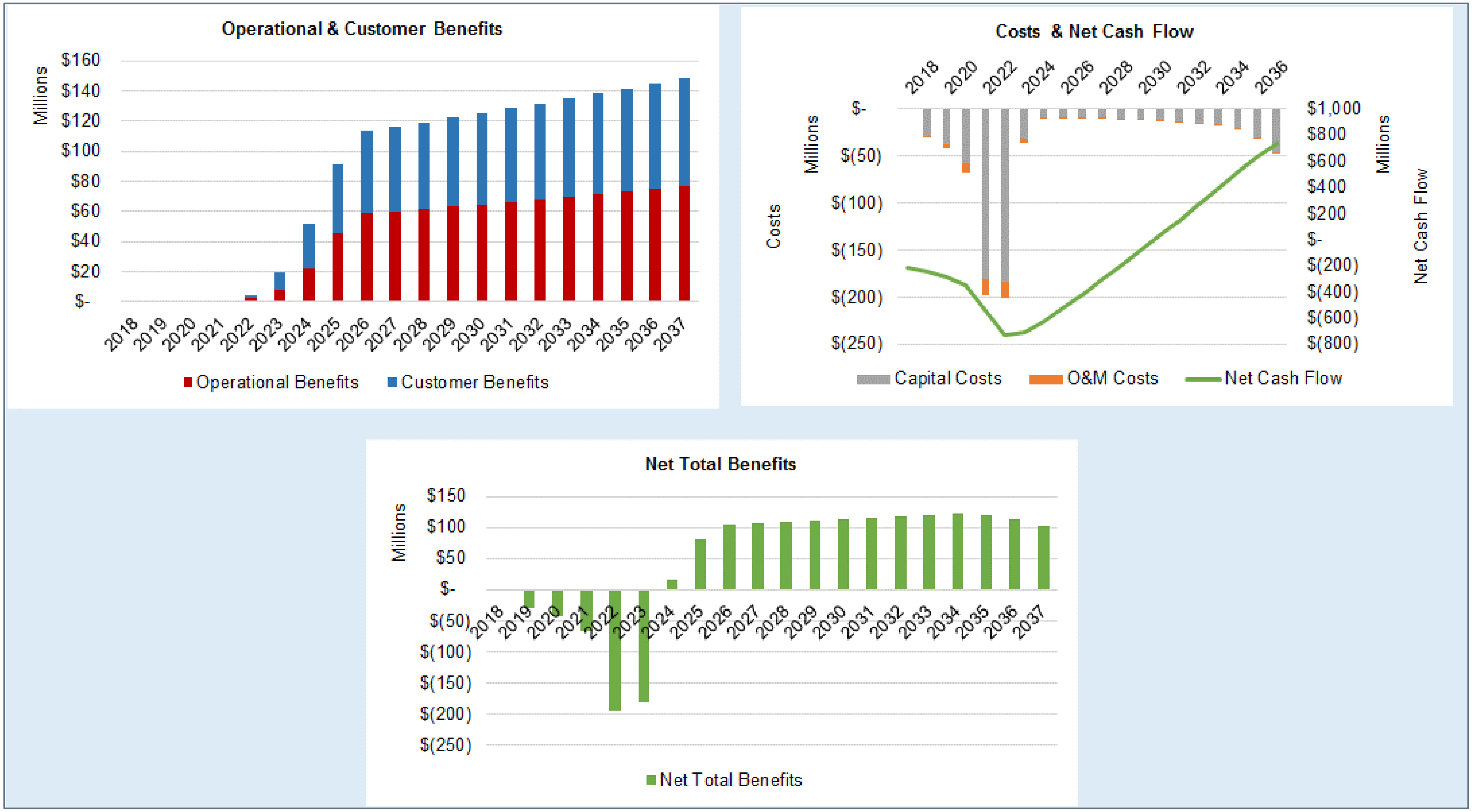
Customer Benefits

Figure 5-6: PSE&G Energy Cloud Customer Benefits

Benefit	Overview/Assumptions	20 Year Phased Benefit (2.5% CPI)
Reduction of bad debt (improvement in field collections)	Reduction in bad debt due to improvement in field collections. Being able to remotely detect and disconnect will reduce the occurrence.	$352,875,005
Reduction in write-offs (and hence rates) related to inactives	Reduction in writes offs due to energy consumed on inactive accounts. Being able to remotely detect and disconnect will reduce the occurrence.	$265,604,842
Avoided theft	Improvement in theft recovery. Being able to remotely analyze meter load and event flags will reduce the occurrence	$137,991,133
Better storm outage response/confirm location of outages/better nested outage identification	Improvement in restoration days and internal and field process of a major storm event by being able to identify nested outages and customers with supply restored through iESP. Costs include internal and external mutual aid crews and exclude Sandy.	$38,437,963
Time of Use Rates	Existing rates – TOU, Demand, Consumption levels.	$37,597,661
Recovered energy loss attributed to slow meters	Improvement in meter accuracy leading to better recovery of energy loss. This considers the average energy loss experienced on meters running slow and subtracts the overestimates on meters running fast.	$10,616,863
Total		**$843,123,467**

5.2.3 Annual Benefits, Costs, Cash Flow, and Net Benefits

Figure 5-7: Annual Benefits, Costs, Cash Flow, and Net Benefits



5.3 USE CASE DATA MAPPING – RELEASE 1

Figure-5-8: Release One Use Case Value / Benefit Areas and Major Data Type Requirements

#	Use Case (22 Release 1 Use Cases)	Value & Benefit Areas				Major Data Types Required (Potential)																
		Increased Product & Service Adoption	Avoided Cost (Trucks, FTEs, Materials, O&M, Capital)	Improved Service (Customers, PQ, Reliability)	Increased Efficiency/ Productivity (People & Process Time)	Customer	Account/ Contract	Voltage	Load/ Consumption	Meter/Events	Premise/ In Home	Asset	Distributed Generation	Network	Product/ Services/ Rates	Call Centre/ Customer Services	Work/ Service Orders	IOT/Social Media	Outage	Market	Location	Weather
1	Enhanced Customer Engagement & Communications	◆	◆	◆		◆	◆	◆	◆	◆	◆		◆	◆		◆	◆	◆	◆	◆	◆	◆
2	Rate Analyzer & Comparator	◆		◆	◆	◆	◆		◆	◆				◆	◆	◆		◆		◆	◆	◆
3	Usage & Bill Alerts, Saving Tips	◆		◆	◆	◆	◆		◆	◆				◆	◆	◆		◆		◆	◆	◆
4	Interactive Energy Demand & Bill Management	◆	◆	◆	◆	◆	◆		◆	◆				◆	◆	◆		◆		◆	◆	◆
5	Customer Segmentation & Behavioural Analysis	◆	◆	◆	◆	◆		◆	◆	◆		◆	◆	◆	◆				◆			
6	Customer Power Quality		◆	◆	◆	◆		◆	◆	◆	◆	◆	◆	◆					◆		◆	◆
7	Customer Energy Efficiency Programs (Thermostats & Supporting CEP Filing)	◆	◆	◆		◆				◆	◆	◆	◆	◆		◆	◆	◆	◆		◆	◆
8	Customer Service & Call Center Performance	◆	◆	◆	◆	◆	◆	◆	◆	◆	◆			◆	◆		◆		◆		◆	
9	Customer DER/PV/EV	◆		◆	◆	◆	◆		◆	◆	◆		◆	◆	◆	◆			◆		◆	◆
10	Customer Device Safety	◆		◆	◆	◆			◆		◆			◆	◆		◆	◆		◆		
11	iESP Sensor, Network & Data Operations		◆	◆	◆	◆		◆	◆	◆		◆		◆			◆				◆	◆
12	Automated Move in/Move		◆	◆	◆	◆	◆		◆	◆	◆		◆	◆	◆	◆	◆				◆	
13	Remote Disconnect/ Reconnect (Primarily in MDMS project)		◆	◆	◆	◆				◆	◆			◆		◆	◆		◆		◆	
14	Next Generation Meter to Cash	◆	◆	◆	◆	◆	◆		◆	◆				◆	◆						◆	
15	Network Connectivity Analysis			◆	◆	◆				◆	◆	◆									◆	
16	Outage Detection & Analysis		◆	◆	◆	◆										◆	◆	◆	◆		◆	
17	Outage & Restoration Notification (ETR)		◆	◆	◆	◆	◆	◆	◆	◆	◆			◆	◆					◆	◆	◆
18	Voltage Monitoring & Analysis (PQ)		◆	◆	◆	◆	◆	◆	◆	◆	◆		◆	◆	◆	◆	◆	◆	◆		◆	◆
19	Asset Load/Phase Management, Balancing & Power Analysis (incl. TLM & Customer Load Curtailment/Limiting)		◆	◆	◆	◆		◆	◆	◆	◆	◆	◆	◆			◆		◆		◆	◆
20	Load Profiling & Research		◆	◆		◆		◆	◆	◆	◆	◆	◆	◆			◆		◆		◆	◆
21	Distribution Losses		◆	◆	◆	◆	◆		◆		◆		◆	◆	◆	◆	◆	◆	◆	◆	◆	◆
22	Revenue Protection & Assurance		◆	◆	◆	◆		◆	◆	◆		◆	◆	◆							◆	◆

ATTACHMENT 1
SCHEDULE GD-CEF-EC-3

PSE&G ENERGY CLOUD CUSTOMER COMMUNICATION STRATEGY

PUBLIC SERVICE ELECTRIC & GAS COMPANY (PSE&G)

October 11, 2018

CONTENTS

1 INTRODUCTION

Public Service Electric & Gas Company (PSE&G or the Company) has developed an Energy Cloud Customer Communications Strategy (Strategy) that will provide the direction and background to create an Energy Cloud Customer Communications Plan (Plan). This Strategy complements the Company's "Next Generation Smart Utility: The Energy Cloud" business case and the reader should refer to the business case for an overview of the Energy Cloud and PSE&G's plans for its deployment.

The primary focus of the Strategy is how to best educate our customers about the benefits of the Energy Cloud Release 1, prepare for its implementation, and address any customer concerns. This includes:

- Educating customers about the components of the Energy Cloud Release 1 and how they can utilize its capabilities and the data made available through its implementation to their benefit;
- Providing customers clear details about the Energy Cloud Release 1 infrastructure deployment schedule and ensuring installers have access to customer residences, as needed; and
- Addressing customer concerns related to the installation of equipment, the technology being deployed, and the use of their data.

The Strategy provides guidance on a series of communications that will allow the Company to develop a Plan tailored to achieve these goals.

The Strategy also provides the terms of the proposed Opt-Out Tariff under which PSE&G would deploy non-communicating meters at a residence in lieu of AMI meters for residential customers who elect to opt-out of the latter.

2 CUSTOMER COMMUNICATIONS PLAN DEVELOPMENT

The Plan will serve as the single source document governing the customer communications that will assist with the successful implementation of the Energy Cloud Release 1. A new Customer Outreach Group will have the responsibility of overseeing the Plan's development and execution.

2.1 CUSTOMER OUTREACH GROUP RESPONSIBILITIES

PSE&G has identified a Customer Outreach Group as part of its proposed organization that would be mobilized to support the Energy Cloud Release 1 deployment.

The Customer Outreach Group will likely consist of a few PSE&G employees developing the content, materials, and messaging for customer engagement communications. The Customer Outreach Group will be comprised of existing associates from Governmental Affairs, Corporate Communications, and Customer Campaign Management teams to finalize and deliver the messages and engage with PSE&G's customers prior to and during Energy Cloud Release 1 deployment.

2.1.1 Determine Preferred Customer Communication Channels

The communications channels used to deliver customer communications will vary based on Company research into customer preferences, demographics, and lessons learned throughout the Energy Cloud implementation. PSE&G has conducted research in the past into the most effective communication channels and will refresh the results of that analysis prior to finalizing the Plan. Refreshing the analysis will allow the Company to communicate with more customers through their preferred channels.

A representative list of the communications channels open to the Company include the following:

- Call center (inbound);
- Phone calls (outbound);
- Walk-in customer service centers;
- Company website;
- Door hangers;
- Direct mail;
- Email;
- Bill messages and inserts;
- Media – press release, social media, and earned media;
- Local and community leaders;
- Infrastructure installer (travels with flier);
- FAQs (includes scientific references and papers and deployment info); and
- Advertising (print, digital, radio, etc.).

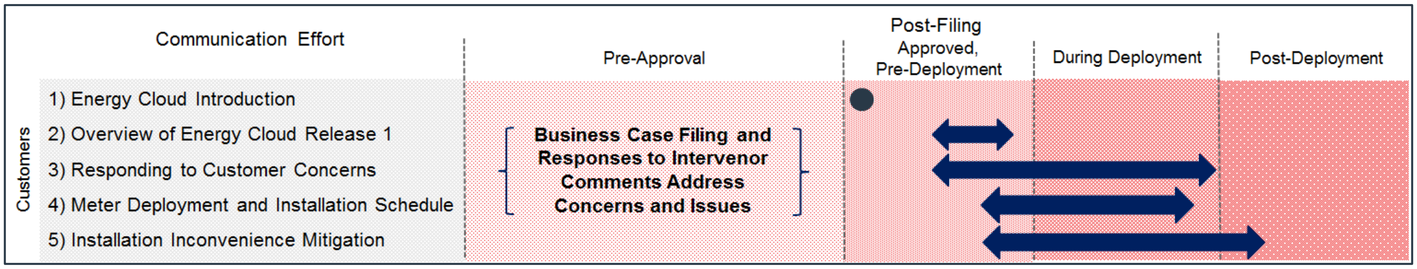
2.1.2 Develop Materials

PSE&G will develop materials to facilitate customer communications. A number of materials have been identified as part of the Strategy along with the objectives and messages they are intended to help communicate. They will be finalized once the communications and channels have been reviewed, refined, and finalized as part of the Plan development.

2.1.3 Review, Refine and Finalize Communications

PSE&G will refine and finalize the customer communications for inclusion in the Plan following approval of the Energy Cloud Program by the BPU. PSE&G has developed a series of customer communications for inclusion in this Strategy as guidance. They include five primary communication activities conducted over four stages: 1) post filing and pre-BPU approval, 2) following BPU approval but prior to Energy Cloud Release 1 deployment, 3) during initial implementation of the Energy Cloud Release 1, and 4) following the Energy Cloud Release 1 deployment.

Figure 1: Customer Communications Overview



The Strategy goes into further detail about these communications in the subsequent section. Where possible, suggested specifics about each communication effort are provided for consideration by the Customer Outreach Group around the:

- Objectives – the intended goal of the interaction;
- Key Messages – what the stakeholder and/or PSE&G should take away from the interaction;
- Audience – intended message recipient;
- Channels – methods by which the communications take place; and
- Materials – means to support communication of the message.

2.2 CUSTOMER MESSAGING PRIOR TO BPU APPROVAL

While the Plan will address communications following BPU approval of the Energy Cloud Program, PSE&G will begin communicating with customers and other stakeholders about the Energy Cloud as soon as the Company submits the filing. These communications will be done on an ongoing basis across a myriad of channels through the filing process and are intended to, among other things, make customers, key stakeholders, and employees aware that PSE&G has filed the Energy Cloud Program, and identify the objective and need for the Energy Cloud Program.

These communications will be developed and delivered by the Governmental Affairs, Corporate Communications, and Customer Campaign Management teams.

2.3 SUMMARY OF CUSTOMER COMMUNICATIONS FOLLOWING BPU APPROVAL

Communications with customers are critical to facilitating the PSE&G Energy Cloud implementation. The initiatives discussed below identify recommended interactions to educate customers about the benefits of the PSE&G Energy Cloud, communicate the deployment plan, and address lingering concerns stemming from the deployment.

2.3.1 Communication Effort 1: Energy Cloud Introduction

The Company's first external communication effort upon receiving approval from the BPU for the PSE&G Energy Cloud will be a press release. The press release will be intended for all external stakeholders, including customers, and will explain that the Energy Cloud has been approved, what it is, and identify the next steps for its deployment. This will likely be the first time many of the Company's customers will hear about the Energy Cloud and this communication effort is intended to describe the initiative and identify when and where additional information will be made available.

Table 1: Energy Cloud Introduction Press Release

Communication Effort 1: Energy Cloud Introduction	
Stage	Approved, Pre-Deployment
Timing	Upon BPU approval
Objectives	• Introduce the Energy Cloud • Identify next steps in the communications and deployment processes
Key Messages	• Announce the BPU's approval of the Energy Cloud • Education about Energy Cloud benefits and opportunities • Timing of follow-up communications

Communication Effort 1: Energy Cloud Introduction	
Audience	• External stakeholders, including customers
Channels	• Media – press release, social media and earned media • Company website
Materials	• Introduction letter and notification • Fact sheet

2.3.2 Communication Effort 2: Overview of Energy Cloud Release 1

The second communication effort following BPU approval is intended to build awareness among PSE&G customers by educating them about the benefits of the Energy Cloud to set the stage for a successful deployment where the intended benefits are realized and customers feel empowered and buy into the program, which will minimize the number of customers who opt-out.

This communication effort is anticipated to begin approximately 60 days before deployment begins. It will build upon communications undertaken by Governmental Affairs, Corporate Communications, and Customer Campaign Management which will begin the stakeholder awareness effort once the Energy Cloud is filed with the BPU through when a BPU decision is reached.

Table 2: Overview of Energy Cloud – Release 1 Customer Communications

Communication Effort 2: Overview of Energy Cloud Release 1	
Stage	Approved, Pre-Deployment
Timing	60 days prior to deployment
Objectives	• Educate customers about device benefits and programs • Maximize device understanding; avoid opt-outs • Ease communications network and device deployment
Key Messages	• Deployment overview; leverage learnings from initial AMI deployment to large industrial and commercial customers • Reinforce that gas meters are moving to drive-by reading • Education about smart device benefits and opportunities • Information on privacy, security, and health concerns • Overview of Company portal • Timing of follow-up notification for device change scheduling • Device installation process and customer responsibilities • Ways to conserve energy and money
Audience	• Customers
Channels	• Direct mail – “Intro. Notification” • Email • Bill messages and inserts • Media – press release, social media and earned media • Local and community leaders • Company’s website • Advertising • Company call and walk-in centers
Materials	• Intro. Notification • Fact sheet

Communication Effort 2: Overview of Energy Cloud Release 1	
	• Infographic • FAQs • Deployment overview (map) • Generic customer messages (alerts)

2.3.3 Communication Effort 3: Responding to Customer Concerns

PSE&G will conduct proactive and reactive communications with customers to allay any concerns about the Energy Cloud deployment. Where appropriate, radio frequency and cyber and data safety, security, and privacy facts will be disseminated and explained to promote informed customers.

This communication effort is anticipated to begin concurrently with Communication Effort 2 and continue through the completion of Energy Cloud Release 1 deployment.

Table 3: Communications Responding to Customer Concerns

Communication Effort 3: Responding to Customer Concerns	
Stage	Approved, Pre-Deployment and During Deployment
Timing	Begins concurrently with Communication Effort 2 and continues through the completion of device deployment
Objectives	• Address customer concerns not assuaged by Communication Effort 2 • Address any customer concerns not assuaged by Device Deployment and Installation Schedule communications (Communication 4, described below) • Continued education of customers • Reduce opt-outs
Key Messages	• Reinforcing information disseminated during Communication Effort 2 • Reinforcing information disseminated during Device Deployment and Installation Schedule communications (described below) • Benefits of smart devices, including customer bill savings • Safety, security, and privacy facts • Opt-out processes and charges
Audience	• Concerned customers
Channels	• Call centers (inbound) • Phone calls (outbound) • Walk-in customer service centers • Company website • Policy letters • Infrastructure installer (travels with flier)
Materials	• Call center talking points • Walk-in center talking points • FAQs (includes scientific references and papers)

2.3.4 Communication Effort 4: Device Deployment and Installation Schedule

PSE&G will conduct additional communications with customers 45 days before the deployment of Energy Cloud Release 1 infrastructure to prepare them for the process and continue informing them of the Energy Cloud benefits. The process for customers to opt-out will be communicated a final time to ensure those who choose this option are informed about their responsibilities and opt-out costs. Opt-out requests should made within 15 days of receipt of the notification to provide PSE&G sufficient time to plan for not installing a non-AMI meter.

Because the deployment of Energy Cloud Release 1 infrastructure will proceed in a phased way across the Company's service territory, these pre-deployment communications will begin 45 days before the Energy Cloud deployment stage and continue until 45 days before the final infrastructure is deployed.

Table 4: Device Deployment and Installation Schedule Communications

Communication Effort 4: Device Deployment and Installation Schedule	
Stage	Approved, Pre-Deployment
Timing	45 days prior to device deployment for each customer (continues throughout deployment schedule)
Objectives	• Provide clear and accurate information to prepare customers for device installation • Facilitate device deployment • Provide information on customer data security and privacy
Key Messages	• Device replacement timing • Customer benefits and what they may expect • Directions for customer Portal access • Opt-out information • Customer data security and privacy • Contact information • Details about who is performing the device installation
Audience	• Deployment area customers
Channels	• Direct mail (45-day notification) • Email • Company's website (deployment map, FAQs, customer data access) • Infrastructure installer (travels with flier) • Call centers • Walk-in customer service centers • Letter for difficult to access customers (multiple letters based on number of failed attempts) • Social media (responding to customer issues raised on these platforms)
Materials	• 45-day notification • Door hanger – install complete and key information • Door hanger – "Sorry we missed you" with appropriate contact details • Device deployment installer FAQs • Company call and walk-in center scripting • Program opportunities as appropriate

2.3.5 Communication Effort 5: Installation Inconvenience Mitigation

PSE&G will conduct a communications effort to address customer concerns resulting from the installation of AMI. These communications will typically be initiated by the customer and handled by the call center representatives, who will rely on existing Company policies and procedures to address any issues (*e.g.*, damage to a customer's premises resulting from meter installation, additional questions about the installation process). These communications will run from the pre- to post-deployment stages.

Table 5: Installation Inconvenience Mitigation Communications

Communication Effort 5: Installation Inconvenience Mitigation

Communication Effort 5: Installation Inconvenience Mitigation	
Stage	Approved, Pre-Deployment, During Deployment, and Post Deployment
Timing	60 days prior to installation through post-installation
Objectives	Address customer concerns resulting from installation of the new device (both during lead up to and following device installation)
Key Messages	• Appointment scheduling • Property damage recovery process • Utility bill explanation
Audience	Concerned or impacted customers
Channels	• Call centers • Walk-in customer service centers • Infrastructure installer
Materials	Phone talking points

3 AMI METER OPT-OUT

Residential customers may elect to opt-out of receiving an AMI meter under the terms proposed below.

3.1 AMI OPT-OUT TARIFF

3.1.1 Eligibility

Residential customers who are not comfortable with the technology or have other concerns following the Company's education and outreach efforts will be eligible to opt-out of receiving an AMI meter. Commercial and industrial customers will not be subject to opting out of AMI.

3.1.2 Cost

Meter Replacements

Customers will be charged a one-time charge of $45.00 for the replacement of an AMI meter with a non-AMI meter. The replacement meter will be a solid state, digital, non-radio frequency emitting meter that will be manually read..

Monthly Meter Reading

Customers who choose to opt-out of receiving AMI meters will incur a $20 monthly meter reading cost per account, regardless of whether an AMI device was installed at their residence.

3.1.3 Responsibility

PSE&G will notify customers in writing that AMI meters are to be installed at least 45 days in advance of the AMI meter installation. This communication will provide details about the opt-out process and notify customers that opt-out requests should made within 15 days of receipt of the notification. It will also include the opt-out and replacement fees discussed above. The objective of this communication is to minimize instances where customers receive AMI meters prior to them notifying the Company of their intent to opt-out.

Attachment 1

Schedule DG-CEF-EC-4A

Electric Delivery Capital Summary (2012 - 2017)

($ in millions)

Capital Category	2012 Full Year Actual	2013 Full Year Actual	2014 Full Year Actual	2015 Full Year Actual	2016 Full Year Actual	2017 Full Year Actual
New Business	$ 58.7	$ 110.6	$ 102.6	$ 113.4	$ 119.3	$ 124.9
Base	**$ 211.4**	**$ 181.1**	**$ 164.6**	**$ 188.8**	**$ 226.1**	**$ 357.5**
Energy Strong			$ 54.1	$ 181.7	$ 252.0	$ 108.9
CIP II	$ 140.5	$ 21.1				
Total Capital $	**$ 410.7**	**$ 312.8**	**$ 321.3**	**$ 484.0**	**$ 597.4**	**$ 591.4**

Base Breakdown by Major Category

Replace Facilities	$ 162.6	$ 113.1	$ 104.0	$ 101.0	$ 123.0	$ 172.0
System Reinforcement	$ 38.0	$ 43.6	$ 34.6	$ 55.5	$ 74.3	$ 146.8
Environmental Regulatory	$ (6.8)	$ 9.7	$ 9.2	$ 9.4	$ 8.4	$ 7.5
Replace Meters	$ 13.3	$ 13.3	$ 11.8	$ 15.2	$ 14.9	$ 16.4
Support Facilities	$ 4.3	$ 1.5	$ 5.0	$ 7.7	$ 5.5	$ 14.8
Base Total $	**$ 211.4**	**$ 181.1**	**$ 164.6**	**$ 188.8**	**$ 226.1**	**$ 357.5**

Attachment 1
Schedule DG-CEF-EC-4B

Electric Delivery Capital Summary (2019 - 2023)

($ in millions)

Capital Category ($M)	2019 Full Year Plan	2020 Full Year Plan	2021 Full Year Plan	2022 Full Year Plan	2023 Full Year Plan
Total Base	**233**	**233**	**233**	**233**	**233**
New Business	114	113	116	118	118
Energy Cloud Program					
Recovery Mechanism	35	48	72	225	228
Projected Stipulated Base	4	5	8	25	25
Total Capital $	**$ 386**	**$ 399**	**$ 429**	**$ 601**	**$ 605**

Base Breakdown by Major Category

Replace Facilities	$ 121	$ 117	$ 133	$ 125	$ 125
System Reinforcement	$ 85	$ 91	$ 64	$ 68	$ 68
Environmental Regulatory	$ 5	$ 5	$ 6	$ 12	$ 12
Replace Meters / Other	$ 18	$ 18	$ 18	$ 18	$ 18
Support Facilities	$ 3	$ 2	$ 12	$ 10	$ 10
Base Total $*	**$ 233**	**$ 233**	**$ 233**	**$ 233**	**$ 233**

*The Company proposes to maintain base level spending from 2019-2023 at the projections shown above

Stipulated Base Requirement*	2019	2020	2021	2022	2023	2024	Total
Recovery Mechanism	35	48	72	225	228	40	649
Average Projected Stipulated Base	4	5	8	25	25	4	72
% Stipulated Base							**11%**

* Program forecasted over 60 month period from April 1, 2019 through March 31, 2024

PSE&G Energy Cloud Program
Summary Cash Flows *

Cash Flows ($000s)	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
Program Year - 2019													
Direct In-Service	$ -	$ -	$ -	$ 1,955	$ 1,955	$ 1,955	$ 2,845	$ 2,845	$ 2,845	$ 2,845	$ 2,845	$ 2,845	$ 22,938
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ -	$ -	$ -	$ 527	$ 527	$ 527	$ 527	$ 527	$ 527	$ 527	$ 527	$ 527	$ 4,740
Total	**$ -**	**$ -**	**$ -**	**$ 2,482**	**$ 2,482**	**$ 2,482**	**$ 3,372**	**$ 3,372**	**$ 3,372**	**$ 3,372**	**$ 3,372**	**$ 3,372**	**$ 27,678**
Program Year - 2020													
Direct In-Service	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 41,070
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 540	$ 540	$ 540	$ 540	$ 540	$ 540	$ 540	$ 540	$ 540	$ 540	$ 540	$ 540	$ 6,478
Total	**$ 3,962**	**$ 3,962**	**$ 3,962**	**$ 3,962**	**$ 3,962**	**$ 3,962**	**$ 3,962**	**$ 3,962**	**$ 3,962**	**$ 3,962**	**$ 3,962**	**$ 3,962**	**$ 47,549**
Program Year - 2021													
Direct In-Service	$ 2,955	$ 2,955	$ 2,955	$ 2,955	$ 2,955	$ 2,955	$ 7,417	$ 7,417	$ 7,417	$ 7,417	$ 7,417	$ 7,417	$ 62,232
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 420	$ 420	$ 420	$ 420	$ 420	$ 420	$ 1,260	$ 1,260	$ 1,260	$ 1,260	$ 1,260	$ 1,260	$ 10,083
Total	**$ 3,375**	**$ 3,375**	**$ 3,375**	**$ 3,375**	**$ 3,375**	**$ 3,375**	**$ 8,677**	**$ 8,677**	**$ 8,677**	**$ 8,677**	**$ 8,677**	**$ 8,677**	**$ 72,315**
Program Year - 2022													
Direct In-Service	$ 15,105	$ 15,105	$ 15,105	$ 15,105	$ 15,105	$ 15,105	$ 15,105	$ 15,105	$ 15,105	$ 15,105	$ 15,105	$ 15,105	$ 181,259
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 3,652	$ 3,652	$ 3,652	$ 3,652	$ 3,652	$ 3,652	$ 3,652	$ 3,652	$ 3,652	$ 3,652	$ 3,652	$ 3,652	$ 43,823
Total	**$ 18,757**	**$ 18,757**	**$ 18,757**	**$ 18,757**	**$ 18,757**	**$ 18,757**	**$ 18,757**	**$ 18,757**	**$ 18,757**	**$ 18,757**	**$ 18,757**	**$ 18,757**	**$ 225,082**
Program Year - 2023													
Direct In-Service	$ 15,272	$ 15,272	$ 15,272	$ 15,272	$ 15,272	$ 15,272	$ 15,272	$ 15,272	$ 15,272	$ 15,272	$ 15,272	$ 15,272	$ 183,270
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 3,743	$ 3,743	$ 3,743	$ 3,743	$ 3,743	$ 3,743	$ 3,743	$ 3,743	$ 3,743	$ 3,743	$ 3,743	$ 3,743	$ 44,918
Total	**$ 19,016**	**$ 19,016**	**$ 19,016**	**$ 19,016**	**$ 19,016**	**$ 19,016**	**$ 19,016**	**$ 19,016**	**$ 19,016**	**$ 19,016**	**$ 19,016**	**$ 19,016**	**$ 228,188**
Program Year - 2024													
Direct In-Service	$ 10,867	$ 10,867	$ 10,867	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 32,600
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 2,603	$ 2,603	$ 2,603	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,808
Total	**$ 13,469**	**$ 13,469**	**$ 13,469**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 40,408**
Totals													
Direct In-Service	$ 47,622	$ 47,622	$ 47,622	$ 38,710	$ 38,710	$ 38,710	$ 44,062	$ 44,062	$ 44,062	$ 44,062	$ 44,062	$ 44,062	$ 523,369
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 10,958	$ 10,958	$ 10,958	$ 8,882	$ 8,882	$ 8,882	$ 9,722	$ 9,722	$ 9,722	$ 9,722	$ 9,722	$ 9,722	$ 117,850
Total	**$ 58,580**	**$ 58,580**	**$ 58,580**	**$ 47,592**	**$ 47,592**	**$ 47,592**	**$ 53,784**	**$ 53,784**	**$ 53,784**	**$ 53,784**	**$ 53,784**	**$ 53,784**	**$ 641,220**

* Totals above reflect only the amount being sought for accelerated recovery, which is 90% of total expenditures starting on April 1, 2019

PSE&G Energy Cloud Program
Smart Meters Cash Flow *

Cash Flows ($000s)	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
Program Year - 2019													
Direct In-Service	$ -	$ -	$ -	$ 1,955	$ 1,955	$ 1,955	$ 1,955	$ 1,955	$ 1,955	$ 1,955	$ 1,955	$ 1,955	$ 17,597
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ -	$ -	$ -	$ 527	$ 527	$ 527	$ 527	$ 527	$ 527	$ 527	$ 527	$ 527	$ 4,740
Total	**$ -**	**$ -**	**$ -**	**$ 2,482**	**$ 2,482**	**$ 2,482**	**$ 2,482**	**$ 2,482**	**$ 2,482**	**$ 2,482**	**$ 2,482**	**$ 2,482**	**$ 22,338**
Program Year - 2020													
Direct In-Service	$ 2,212	$ 2,212	$ 2,212	$ 2,212	$ 2,212	$ 2,212	$ 2,212	$ 2,212	$ 2,212	$ 2,212	$ 2,212	$ 2,212	$ 26,539
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 540	$ 540	$ 540	$ 540	$ 540	$ 540	$ 540	$ 540	$ 540	$ 540	$ 540	$ 540	$ 6,478
Total	**$ 2,751**	**$ 2,751**	**$ 2,751**	**$ 2,751**	**$ 2,751**	**$ 2,751**	**$ 2,751**	**$ 2,751**	**$ 2,751**	**$ 2,751**	**$ 2,751**	**$ 2,751**	**$ 33,017**
Program Year - 2021													
Direct In-Service	$ 2,231	$ 2,231	$ 2,231	$ 2,231	$ 2,231	$ 2,231	$ 6,692	$ 6,692	$ 6,692	$ 6,692	$ 6,692	$ 6,692	$ 53,538
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 420	$ 420	$ 420	$ 420	$ 420	$ 420	$ 1,260	$ 1,260	$ 1,260	$ 1,260	$ 1,260	$ 1,260	$ 10,083
Total	**$ 2,651**	**$ 2,651**	**$ 2,651**	**$ 2,651**	**$ 2,651**	**$ 2,651**	**$ 7,953**	**$ 7,953**	**$ 7,953**	**$ 7,953**	**$ 7,953**	**$ 7,953**	**$ 63,621**
Program Year - 2022													
Direct In-Service	$ 14,950	$ 14,950	$ 14,950	$ 14,950	$ 14,950	$ 14,950	$ 14,950	$ 14,950	$ 14,950	$ 14,950	$ 14,950	$ 14,950	$ 179,396
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 3,652	$ 3,652	$ 3,652	$ 3,652	$ 3,652	$ 3,652	$ 3,652	$ 3,652	$ 3,652	$ 3,652	$ 3,652	$ 3,652	$ 43,823
Total	**$ 18,602**	**$ 18,602**	**$ 18,602**	**$ 18,602**	**$ 18,602**	**$ 18,602**	**$ 18,602**	**$ 18,602**	**$ 18,602**	**$ 18,602**	**$ 18,602**	**$ 18,602**	**$ 223,219**
Program Year - 2023													
Direct In-Service	$ 15,169	$ 15,169	$ 15,169	$ 15,169	$ 15,169	$ 15,169	$ 15,169	$ 15,169	$ 15,169	$ 15,169	$ 15,169	$ 15,169	$ 182,028
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 3,743	$ 3,743	$ 3,743	$ 3,743	$ 3,743	$ 3,743	$ 3,743	$ 3,743	$ 3,743	$ 3,743	$ 3,743	$ 3,743	$ 44,918
Total	**$ 18,912**	**$ 18,912**	**$ 18,912**	**$ 18,912**	**$ 18,912**	**$ 18,912**	**$ 18,912**	**$ 18,912**	**$ 18,912**	**$ 18,912**	**$ 18,912**	**$ 18,912**	**$ 226,946**
Program Year - 2024													
Direct In-Service	$ 10,867	$ 10,867	$ 10,867	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 32,600
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 2,603	$ 2,603	$ 2,603	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,808
Total	**$ 13,469**	**$ 13,469**	**$ 13,469**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 40,408**
Totals													
Direct In-Service	$ 45,428	$ 45,428	$ 45,428	$ 36,516	$ 36,516	$ 36,516	$ 40,978	$ 40,978	$ 40,978	$ 40,978	$ 40,978	$ 40,978	$ 491,698
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 10,958	$ 10,958	$ 10,958	$ 8,882	$ 8,882	$ 8,882	$ 9,722	$ 9,722	$ 9,722	$ 9,722	$ 9,722	$ 9,722	$ 117,850
Total	**$ 56,385**	**$ 56,385**	**$ 56,385**	**$ 45,398**	**$ 45,398**	**$ 45,398**	**$ 50,700**	**$ 50,700**	**$ 50,700**	**$ 50,700**	**$ 50,700**	**$ 50,700**	**$ 609,549**

* Totals above reflect only the amount being sought for accelerated recovery, which is 90% of total expenditures starting on April 1, 2019

PSE&G Energy Cloud Program
Network Communication Cash Flow *

Cash Flows ($000s)	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
Program Year - 2019													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ 890	$ 890	$ 890	$ 890	$ 890	$ 890	$ 5,341
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 890**	**$ 890**	**$ 890**	**$ 890**	**$ 890**	**$ 890**	**$ 5,341**
Program Year - 2020													
Direct In-Service	$ 1,211	$ 1,211	$ 1,211	$ 1,211	$ 1,211	$ 1,211	$ 1,211	$ 1,211	$ 1,211	$ 1,211	$ 1,211	$ 1,211	$ 14,531
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 1,211**	**$ 1,211**	**$ 1,211**	**$ 1,211**	**$ 1,211**	**$ 1,211**	**$ 1,211**	**$ 1,211**	**$ 1,211**	**$ 1,211**	**$ 1,211**	**$ 1,211**	**$ 14,531**
Program Year - 2021													
Direct In-Service	$ 725	$ 725	$ 725	$ 725	$ 725	$ 725	$ 725	$ 725	$ 725	$ 725	$ 725	$ 725	$ 8,694
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 725**	**$ 725**	**$ 725**	**$ 725**	**$ 725**	**$ 725**	**$ 725**	**$ 725**	**$ 725**	**$ 725**	**$ 725**	**$ 725**	**$ 8,694**
Program Year - 2022													
Direct In-Service	$ 155	$ 155	$ 155	$ 155	$ 155	$ 155	$ 155	$ 155	$ 155	$ 155	$ 155	$ 155	$ 1,863
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 155**	**$ 155**	**$ 155**	**$ 155**	**$ 155**	**$ 155**	**$ 155**	**$ 155**	**$ 155**	**$ 155**	**$ 155**	**$ 155**	**$ 1,863**
Program Year - 2023													
Direct In-Service	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 1,242
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 104**	**$ 104**	**$ 104**	**$ 104**	**$ 104**	**$ 104**	**$ 104**	**$ 104**	**$ 104**	**$ 104**	**$ 104**	**$ 104**	**$ 1,242**
Program Year - 2024													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Totals													
Direct In-Service	$ 2,194	$ 2,194	$ 2,194	$ 2,194	$ 2,194	$ 2,194	$ 3,084	$ 3,084	$ 3,084	$ 3,084	$ 3,084	$ 3,084	$ 31,671
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 2,194**	**$ 2,194**	**$ 2,194**	**$ 2,194**	**$ 2,194**	**$ 2,194**	**$ 3,084**	**$ 3,084**	**$ 3,084**	**$ 3,084**	**$ 3,084**	**$ 3,084**	**$ 31,671**

* Totals above reflect only the amount being sought for accelerated recovery, which is 90% of total expenditures starting on April 1, 2019

ATTACHMENT 2

STATE OF NEW JERSEY

BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF ITS CLEAN ENERGY FUTURE-ENERGY CLOUD PROGRAM ON A REGULATED BASIS

BPU Docket No. __________

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
DONNA POWELL
ASSISTANT CONTROLLER – PSE&G

October 11, 2018

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
DONNA M. POWELL
ASSISTANT CONTROLLER – PSE&G

Q. In what capacity are you employed?

A. I am employed by PSEG Services Corporation (PSEG Services), a subsidiary of Public Service Enterprise Group Incorporated (PSEG or Enterprise), as Assistant Controller - PSE&G. I am responsible for all accounting matters for PSE&G. My business address is 80 Park Plaza, Newark, NJ.

Q. Please describe your employment experience and educational background.

A. I hold a B.S. in Accounting from Villanova University and I am a Certified Public Accountant. I have been employed by PSEG Services since 2012, serving as the Assistant Controller for PSE&G. In my role as Assistant Controller PSE&G, I am responsible for all accounting matters for PSE&G and I direct the utility accounting functions including regulatory compliance thereon. I have previously testified on behalf of PSE&G to the New Jersey Board of Public Utilities (the “Board” or “BPU”).

Prior to joining PSEG, I was employed by New Jersey American Water Company from 2007 to 2012 as Vice-President of Finance where I was responsible for all of the financial aspects of that company, including business planning, regulatory strategy and rate support, and all financial, statutory and management reporting. From 1998 to 2007, I worked in various financial capacities at Pepco Holdings, Inc. (formerly Conectiv, Inc. and Atlantic City Electric Company), including testifying before the New Jersey Board of Public Utilities in 1998 in support of Atlantic City Electric Company's request for stranded cost recovery as a result of deregulation. I also worked for nine years with Deloitte & Touche in various capacities from entry level auditor through Senior Manager where, in that role, I worked primarily in the utility sector and was a designated utility industry accounting and auditing expert.

Q. Please describe the purpose of your testimony.

A. I am testifying in support of the Company's proposed Clean Energy Future - Energy Cloud Program ("EC" or the "Program"), specifically to explain the accounting and proposed regulatory treatment for costs related to the intelligent energy service platform ("iESP"). My testimony will discuss how the Company accounts for capital assets and their retirement, and how the proposed deployment of Advanced Metering Infrastructure ("AMI") requires special regulatory and accounting treatment. Additionally, I will discuss the operations and maintenance ("O&M") costs related to the program and PSE&G's request to defer these costs.

Q. Please summarize the Company's requested regulatory accounting treatment.

A. The Company seeks approval from the BPU for accounting treatment as follows:

- Record a regulatory asset for unrecovered (stranded) meter cost and amortize this over a five-year period commencing after PSE&G's next base rate case.
- Defer and record a regulatory asset for O&M costs of the program, accrue and recover carrying-costs on the regulatory asset at 7 year treasuries plus sixty

basis points and amortize the regulatory asset over a five-year period commencing after the next base rate case.

- Set the book depreciation rate for AMI meters to 20 years.

Q. Please explain a regulated utility's accounting for capital assets.

A. As a regulated public utility, the Company accounts for capital property, plant, and equipment ("PPE") in compliance with Generally Accepted Accounting Principles ("GAAP') and FERC's Uniform System of Accounts ("US of A") and instructions contained therein. When a capital asset is installed, the cost of materials and labor to install that asset increases the gross plant balance on the utility's balance sheet upon placing the asset in-service. To recognize the periodic cost of this asset over time, the asset is depreciated over an average useful life as approved by the utility's regulator and periodically updated through depreciation life studies. The periodic cost charged or debited to the income statement is recorded as "depreciation expense" with an offsetting credit to the accumulated depreciation reserve. The accumulated depreciation reserve is reported as a contra asset (or offset) to the asset balances on the Company's balance sheet, and subtracted from gross PPE for calculation of rate base in rate proceedings.

When utility assets are replaced and retired from service in the normal course of business, the accounting entry removes the original cost from both the gross plant balance and the accumulated depreciation balance. This regulatory accounting structure recognizes that net plant, as a component of rate base, should reflect the full value of the asset, allowing the Company to get full recovery of its capital investment. The accumulated depreciation reserve, which has been charged for the gross or original cost, is evaluated periodically as part of a depreciation study, which serves to re-set the useful service life of the asset class taken as a whole.

Q. Please explain the accounting impact for atypical mass retirements such as the proposed replacement of approximately 2.2 million meters over the next 5 years.

A. As required under GAAP, the annual depreciation rate for existing meters would need to dramatically increase to reflect the significantly shorter estimated remaining life of the existing meters, resulting in a corresponding substantial increase in the depreciation expense to fully amortize the balance of the cost of the meters over their shorter remaining life. As of June 30, 2018, the gross plant value of the electric meters to be replaced under this program was approximately $235 million, and the accumulated depreciation was $16 million, making the net plant value $219 million. These were prudently incurred costs and the assets are used and useful, but are being proposed to be replaced on an accelerated basis by assets that can provide superior service and provide more value to customers. The estimated depreciation expense would increase to approximately $44 million per year over the 5 years of the Program for a total of $219 million required to fully depreciate the existing meter assets. The Company seeks to defer the incremental depreciation expense not currently recovered in rates. Without specific regulatory treatment, this will result in a significant adverse financial impact to the Company.

Q. How does the Company propose to recover the remaining undepreciated book value of the existing meters that will be retired with the deployment of the advanced meters?

A. In order to recover the undepreciated net book value of the meters, the Company proposes to move the net increase in meter depreciation expense to a regulatory asset account (Account 182) and to recover the regulatory asset balance over a five-year period commencing at the conclusion of the Company's next base rate case. The Company will not accrue interest on the regulatory asset balance. Also, in the subsequent base rate case, the retired meters will not be part of rate base and the Company will no longer seek a return on them. We seek approval from the BPU to undertake this accounting treatment.

Q. Is the accounting treatment proposed by the Company in accordance with GAAP?

A. Yes. U.S. GAAP specifically discusses the accounting for a regulator's actions designed to protect a utility from the effects of regulatory lag or gap in cost recovery. Topic 980 of the FASB's Accounting Standards Codification ("ASC") covers the accounting guidance for regulated operations formerly provided in Statement of Financial Accounting Standards No. 71. Costs associated with regulatory lag can be capitalized for accounting purposes, provided the provisions of ASC 980-340-25-1 are met. The guidance states:

> Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An enterprise shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met: (a) It is probable (as defined in Topic 450) that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for ratemaking purposes and (b) Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar

> future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost. A cost that does not meet these asset recognition criteria at the date the cost is incurred shall be recognized as a regulatory asset when it does meet those criteria at a later date.

For the Company to create the proposed regulatory asset, it must be probable that such costs will be recovered through rates in future periods. To satisfy the probability standard, the BPU's order in this proceeding should specifically approve the accounting and recovery mechanism as proposed.

Q. Please explain the capital costs associated with iESP.

A. During the iESP deployment and subsequent years, PSE&G will follow its standard accounting practices when deciding which costs incurred qualify as capital or operations and maintenance (O&M). Based on my initial review of the work proposed in the iESP business plan, the program spending qualifies as capital as meter and network communication equipment. As discussed in Gregory Dunlap's testimony, PSE&G plans on spending $721 million of capital costs during the iESP deployment through 2024.

Q. Please explain the O&M expense associated with iESP.

A. Although the majority of costs related to iESP are estimated to be capital, PSE&G is expected to incur significant O&M expenses during the iESP deployment. These costs include customer communications and education activities, employee training, and meter testing. These costs are incremental to current O&M costs. As discussed in Gregory

Dunlap's testimony, PSE&G anticipates spending an additional $73 million of O&M during the iESP deployment through 2024.

Q. What does PSE&G request from the BPU related to the project O&M costs?

Even though these are "O&M" costs, they are incremental to costs currently in base rates and are incurred solely due to the AMI deployment. As a result, these costs are integral to and inextricably linked to the project and are part of the total costs of the project, regardless of capital or O&M classifications. Therefore, PSE&G requests authority to defer the O&M costs associated with deployment to a regulatory asset, and to recover those costs over the five-year period commencing after PSE&G's next base rate case. Under this proposal, the regulatory asset will be recorded as the O&M costs are incurred. The Company requests that it be allowed to record a carrying charge on this asset at 7 year treasuries plus sixty basis points. In the absence of such treatment, the Company would incur costs that could have a material adverse effect on its earnings, cash flows and return on equity. We seek approval from the BPU to undertake this accounting treatment.

Q. Has the Company ever requested and received approval to defer project-related O&M in the past.

A. Yes. The Company completed installation of a new customer care system in 2009. The Company deferred O&M costs incurred for this project and requested recovery in its prior base rate case that was completed in 2010. The Company received approval to recover $24 million over a four-year period. The Company also has several programs in which O&M costs are included in project cost recovery, including its Energy Efficiency programs.

Q. What are the proposed book and tax depreciable lives for the program costs?

A. Please see Figure 1 below for a summary of the proposed depreciation lives.

Figure 1

Asset Type	**Book Life**	**Tax Life**
Meters	20-year straight life	10-year MACRS life
Network Communication Equipment	10-year straight life	7-year MACRS life
Deferred O&M	5 years	Expensed when incurred
Deferred Stranded Costs	5 years	Not applicable

The proposed book life of AMI meters matches the expected useful life of 20 years. We seek approval from the BPU to set this depreciation rate. The book life of the communication equipment follows existing life expectancy for asset class 397. Similarly, the tax treatment of the assets will follow IRS rules.

As discussed, PSE&G proposes to amortize the regulatory assets for deferred O&M and stranded meter costs over five years commencing at the conclusion of PSE&G's next base rate case. This timeframe aligns the timing of the program costs with the corresponding benefits, smooths the impact to rate payers, and eliminates large negative impacts on the Company's financial position.

Q. Does this conclude your testimony?

A. Yes.

ATTACHMENT 3

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF ITS CLEAN ENERGY FUTURE-ENERGY CLOUD PROGRAM ON A REGULATED BASIS

BPU Docket No. __________

PUBLIC SERVICE ELECTRIC AND GAS COMPANY DIRECT TESTIMONY OF STEPHEN SWETZ SR. DIRECTOR – CORPORATE RATES AND REVENUE REQUIREMENTS

October 11, 2018

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
STEPHEN SWETZ
SR. DIRECTOR – CORPORATE RATES AND REVENUE REQUIREMENTS

I. INTRODUCTION AND PURPOSE

Q. Please state your name and professional title.

A. My name is Stephen Swetz and I am the Sr. Director – Corporate Rates and Revenue Requirements for PSEG Services Corporation. My credentials are set forth in the attached Schedule SS-CEF-1.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of this testimony is to support Public Service Electric and Gas Company's ("PSE&G" or "the Company") proposed methodology for recovery of the costs related to PSE&G's Clean Energy Future - Energy Cloud Program ("CEF-EC"). I will also address projected bill impacts.

II. CEF-ENERGY CLOUD PROGRAM REVENUE REQUIREMENTS AND COST RECOVERY

Q. Please briefly describe PSE&G's proposed CEF-EC cost recovery methodology.

A. PSE&G is proposing a cost recovery mechanism for CEF-EC consistent with the BPU's approved regulations entitled "Infrastructure Investment And Recovery" under which utilities propose Infrastructure Investment Programs ("IIP")[1]. The details of the costs to be recovered, as well as the mechanism to recover such costs, are set forth in this testimony.

[1] N.J.A.C. 14:3-2A.

A. Revenue Requirement Formula and Components

Q. How does PSE&G propose to calculate the revenue requirements?

A. PSE&G proposes to calculate the revenue requirements associated with the CEF-EC Program costs using the following formula:

*Revenue Requirements = ((After Tax Cost of Capital * Net Rate Base)*

*+ Net of Tax Amortization and/or Depreciation + Tax Adjustment)**

Revenue Factor

The Company is proposing to recover the revenue requirements through semi-annual base rate roll-in filings as described below, which is consistent with the BPU's proposed IIP regulations.

Q. Please describe the components and defined terms in PSE&G's proposed revenue requirement calculation.

A. The following is a description of each term proposed in PSE&G's revenue requirement calculation. The term "Cost of Capital" is PSE&G's overall WACC for the CEF-EC Program. PSE&G shall earn a return on its net investment in the CEF-EC Program based upon an authorized ROE and capital structure including income tax effects. The Company is proposing to utilize the latest cost of capital authorized by the Board in a base rate case proceeding. Since the CEF-EC Program is anticipated to commence after Board approval of the Company's pending base rate case, PSE&G is utilizing the WACC submitted in the Company's pending base rate case for forecasting purposes. See Schedule SS-CEF-EC-1 for the calculation of the current After-Tax WACC utilized in the revenue requirement calculation. Any change in the WACC authorized by the Board in the pending or any subsequent electric, gas, or combined base rate case would be reflected in the subsequent monthly revenue requirement calculations. Any changes to current tax rates would also be reflected in an adjustment to the After-Tax WACC.

The term "Net Rate Base" refers to Gross Plant less the associated accumulated depreciation and/or amortization and less ADIT. Gross Plant is equal to all Plant In-Service. The book recovery of each asset class and its associated tax depreciation will be based on the flowing depreciation rates. The annual book depreciation rate for new advanced metering infrastructure ("AMI") meters is proposed at 5% based on an estimated 20 year book life. The annual book depreciation rate for the network integration investment is 10% based on a 10-year life consistent with other communication equipment. ADIT is calculated as Book Depreciation (Tax Basis) less Tax Depreciation, multiplied by the Company's effective tax rate, which is currently 28.11%. The AMI meters will be depreciated for tax purposes using the 10-year Modified Accelerated Cost Recovery System ("MACRS") schedule. The network integration investment will be depreciated for tax purposes using a 7-year MACRS schedule. Cost of Removal Expenditures are depreciated 100% in the year incurred for tax purposes. Any future changes to the book or tax depreciation rates, such as "bonus depreciation" during the construction period of the CEF-EC Program and at the time of each base rate roll-in, will be reflected in the accumulated depreciation and/or ADIT calculation described above.

The "Net of Tax Depreciation and/or Amortization" allows for recovery of the Company's investment in the CEF-EC Program assets over the useful book life of each asset class. PSE&G proposes to depreciate the CEF-EC assets in accordance with the Company's approved capitalization policy or as ordered by the Board. The book recovery of each asset class is discussed above. For plant in service investment, the net of tax depreciation expense is calculated as the depreciation expense multiplied by one minus the current tax rate. For Construction Work in Progress ("CWIP") projects, there is no tax deduction for the equity portion of the capitalized AFUDC. As a result, the net of tax depreciation expense is calculated as the depreciation expense associated with the Plant In-Service, excluding the equity portion of AFUDC, multiplied by one minus the current tax rate plus the depreciation expense associated with the equity portion of the AFUDC. Since the equity portion of AFUDC will not be included in the tax basis of the CEF-EC Program assets, the equity portion must be grossed-up for taxes in order for the Company to earn its allowed rate of return. Any future changes to the book depreciation or tax rates during the construction period of the CEF-EC Program and at the time of each base rate roll-in, will be reflected in the net of tax depreciation expense calculation described above.

The term "Tax Adjustment" refers to any applicable tax items that may impact the revenue requirement calculation for the CEF-EC Program. There are no tax adjustments forecasted for the CEF-EC Program at this time.

The "Revenue Factor" adjusts the Revenue Requirement Net of Tax for federal and state income taxes and the costs associated with the BPU and Rate Counsel ("RC") Annual Assessments. The BPU/RC Assessment Expenses consist of payments, based upon a percentage of revenues collected (updated annually), to the State based on the gas intrastate operating revenues for the utility. The Company has utilized the respective BPU and RC assessment rates based on the 2018 fiscal year assessment.

Q. Please describe the type of expenditures to be included in Net Rate Base?

A. The CEF-EC Program will include requests for recovery in base rates of all capital expenditures associated with the CEF-EC projects, including actual costs of engineering, design and construction, cost of removal (net of salvage) and property acquisition, including actual labor, materials, overhead, and capitalized AFUDC associated with the projects (the "Capital Investment Costs"). Capital Investment Costs will be recorded, during construction, in an associated CWIP account or in a Plant In-Service account upon the respective project being deemed used and useful.

Q. Will any of the CEF-EC expenditures be eligible for AFUDC?

A. Yes, but only for those projects that meet the Company's criteria for accrual of AFUDC. AFUDC is a component of construction costs representing the net cost of borrowed funds and an equity return rate used during the period of construction. Under the Company's current policy, only projects that have both costs exceeding $5,000 and a construction period longer than 60 days are eligible for AFUDC. Most of the investments under the CEF-EC Program are not anticipated to be eligible for AFUDC because they will take less than 60 days to construct. However, it is possible that some projects will require more than 60 days of construction and will therefore accrue AFUDC. In the event the Company's criteria for the accrual of AFUDC changes, the Company's criteria in place at the time the expenditures are incurred would be applied.

Q. How will AFUDC be calculated on eligible projects?

A. The Company accrues AFUDC on eligible projects utilizing the "full FERC method" as set forth in FERC Order 561. AFUDC is accrued monthly and capitalized to CWIP until the project is placed into service.

Q. Will the Company utilize AFUDC once the projects are placed into service?

A. No. Consistent with the IIP regulations, the Company will not accrue any AFUDC on projects that have already been placed into service.

Q. What is the source of the capital expenditures you use to calculate the revenue requirements?

A. The projected monthly cash flow for the CEF-EC Program projects was provided by Company witness Gregory Dunlap. See Schedule DG-CEF-EC-5.

Q. Is the Company planning capital expenditures similar to those included in EC not to be recovered via the CEF-EC cost recovery mechanism?

A. Yes, the Company plans to maintain capital expenditures of at least 10% of the approved CEF-EC expenditures on projects similar to those proposed in the CEF-EC. These capital expenditures shall be made in the normal course of business and recovered in future base rate proceedings, and shall not be subject to the recovery via the CEF-EC cost recovery mechanism.

B. Rate Adjustment Timing and IIP Requirements

Q. How does the Company propose to recover the revenue requirements as described above?

A. The Company proposes to recover the revenue requirements associated with the CEF-EC Program through semi-annual rate base roll-in filings, which is consistent with the recently enacted BPU IIP regulations. The Company is seeking recovery of the CEF-EC work starting April 1, 2019. The proposed schedule for the Rates Effective, Initial Filing, Investment as of, and True-up Filing dates for all roll-ins is listed below:

Potential EC Rate Roll-in Schedule				
Roll-in #	**Rates Effective**	**Initial Filing**	**Investment as of**	**True-up Filing**
1	6/1/20	12/31/19	2/29/20	3/15/20
2	12/1/20	6/30/20	8/31/20	9/15/20
3	6/1/21	12/31/20	2/28/21	3/15/21
4	12/1/21	6/30/21	8/31/21	9/15/21
5	6/1/22	12/31/21	2/28/22	3/15/22
6	12/1/22	6/30/22	8/31/22	9/15/22
7	6/1/23	12/31/22	2/28/23	3/15/23
8	12/1/23	6/30/23	8/31/23	9/15/23
Final	1/31/24	7/31/24	3/31/24	4/15/24

Q. Is the Company proposing a minimum investment level to complete a base rate roll-in?

A. Yes. Consistent with the IIP regulations, the Company proposes to limit each base rate roll-in to a minimum investment level of 10 percent of the total program investment. The program investment is defined as all capital expenditures as defined previously in my testimony excluding AFUDC. As a result, based on the proposed capital expenditure forecast, the first base rate roll-in filing will not occur until December 31, 2019 for rates effective June 1, 2020.

Q. Is there any other proposed limit that could impact the amount of investment to be included in a rate base roll-in?

A. Yes, the Company is also proposing to limit the amount of investment to be included in the rate base roll-in by an earnings test. If the Company exceeds the allowed ROE from its last base rate case by fifty (50) basis points or more for the most recent twelve (12) month period, the pending base rate roll-in shall not be allowed for the applicable filing period.

Q. How does the Company propose to calculate this earnings test?

A. Per the proposed IIP regulations, the earnings test shall be determined based on the actual net income of the Company for the most recent twelve (12) month period divided by the average of the beginning and ending common equity balances for the corresponding period.

Q. What is the corresponding period for the earnings test?

A. The Company will utilize the 12 month period corresponding to the latest available SEC quarterly/annual filing. In the same manner as capital expenditures, the Company will provide 9 months of actual data and 3 months of forecast data at the time of its initial filing. The 3 months of forecasted data will be updated with actual information at the same time the Company updates investment for actuals per the schedule above.

Q. How does the Company propose to calculate the earnings test?

A. The Company proposes to calculate the earnings test consistent with the methodology used for the Company's Board-approved Weather Normalization Clause.

Q. Under this proposal, what opportunity will the BPU and/or Rate Counsel have to review the actual expenditures of the Program?

A. Upon BPU approval of the CEF-EC Program, PSE&G will make semi-annual filings with actual expenditures based on the schedule described above. BPU Staff and Rate Counsel can review each roll-in filing to ensure that the revenue requirements and proposed rates are being calculated in accordance with the BPU Order approving the CEF-EC

Program. The actual prudency of the Company's expenditures in CEF-EC will be reviewed as part of PSE&G's subsequent base rate case(s) following the roll-in(s).

Q. Does the Company plan to file a base rate case in connection with the proposed CEF-EC?

A. Yes. The Company proposes that it will file its next rate case not later than five (5) years after the commencement of CEF-EC.

C. Initial Revenue Requirement

Q. Is there a schedule showing the calculation of the revenue requirements?

A. Yes. See Schedule SS-CEF-EC-2 for the calculation of the CEF-EC revenue requirements based on the forecasted cash flow provided in Schedule DG-CEF-EC-5.

Q. What is the revenue requirement for the initial rate recovery period?

A. The revenue requirement for the first rate change will be for plant in-service from Board approval through November 30, 2020, and is currently forecasted to be $11.282 million. See Schedule SS-CEF-EC-3.

D. Rate Design

Q. What customers do the smart meters and supporting infrastructure serve?

A. The CEF-EC revenue requirement supports all meters for electric residential and metered small commercial customers.

Q. How should the CEF-EC revenue requirement be functionalized for the Company's Embedded Cost of Service Study?

A. Since all the CEF-EC revenue requirement is related to meters and collecting and storing meter data, it would be allocated to the Customer Access function.

Q. How does the Company propose to change rates to collect the CEF-EC revenue requirement?

A. Since the meters serve residential and small commercial customers and are classified to the Customer Access function, the CEF-EC revenue requirement should be collected via the monthly service charge for these customers.

Q. What rate classes will receive the new meters as part of the EC Program?

A. The meters being replaced as part of the CEF-EC Program are for the RS, RHS, RLM and GLP rate classes.

Q. How does the Company plan to allocate the revenue to the rate classes previously mentioned?

A. Since the average cost of GLP meters is higher than the weighted average cost of residential meters, the cost will be allocated on a weighted average basis to each rate class. All of the other costs are the same per meter, so they will be allocated by the number of total meters being installed. See Schedule SS-CEF-EC-3, Table 1, for the calculation of the percentage used for interclass revenue allocation and SS-CEF-EC-3, Table 2, for the calculation of the revenue allocation to each rate class. The monthly service charge for the RLM rate class is currently above its cost to serve. As a result, the Company will not allocate any program costs to that rate class as part of this proceeding.

Q. How does the Company plan to calculate the new monthly service charges?

A. The revenue requirement allocated to each rate class will be divided by the number of customers in each rate class, then divided by 12 for the number of months in a year, and then added to the existing monthly service charge. Please see Schedule SS-CEF-EC-3, Table 3, for the calculation of the proposed monthly service charges without SUT. Schedule SS-CEF-EC-3, Table 4 calculates the new monthly service charges with SUT.

Q. What are the annual rate impacts to the typical residential customer?

A. Based upon the forecasted rates shown in Schedule SS-CEF-EC-3, the typical annual bill impacts for a residential customer as well as rate class average customers compared to rates as of September 8, 2018 are set forth in Schedule Attachment 4[2] Based on the estimated roll-in revenue requirements provided in Schedule SS-CEF-EC-2, the initial annual impact of the proposed rates for the first roll-in period to the typical residential electric customer who uses 750 kilowatt-hours in a summer month and 7,200 kilowatt-hours annually is an increase of $5.52 or approximately 0.45%. The maximum cumulative impact (impact from the entire CEF-EC Program) on the typical residential electric customer is an average annual increase of approximately 3.29% or about a $3.38 increase in their average monthly bill.

Q. Will the Company hold public comment hearings?

A. A proposed form of public notice of filing and public hearings for the CEF-EC Program, including the proposed rates and bill impacts attributable to the proposed implementation of the CEF-EC Program are set forth in Attachment 5.

Q. Does this conclude your testimony at this time?

A. Yes, it does.

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[2] The bill impacts assume that customers receive commodity service from PSE&G under the applicable Basic Generation Service (BGS) rate.

ATTACHMENT 3

SCHEDULE INDEX

Schedule SS-CEF-1	CEF Steve Swetz Credentials
Schedule SS-CEF-EC-1	CEF-EC Weighted Average Cost of Capital (WACC)
Schedule SS-CEF-EC-2	CEF-EC Revenue Requirements Summary
Schedule SS-CEF-EC-3	CEF-EC Rate Design & Tariff Summary

ELECTRONIC WORKPAPER INDEX

WP-SS-CEF-EC-1.xls	CEF-EC Revenue Requirements Summary and Rate Analysis Calculations

CREDENTIALS
OF
STEPHEN SWETZ
SR. DIRECTOR-CORPORATE RATES AND REVENUE REQUIREMENTS

My name is Stephen Swetz and I am employed by PSEG Services Corporation. I am the Sr. Director - Corporate Rates and Revenue Requirements where my main responsibility is to contribute to the development and implementation of electric and gas rates for Public Service Electric and Gas Company (PSE&G, the Company).

WORK EXPERIENCE

I have over 25 years of experience in Rates, Financial Analysis and Operations for three Fortune 500 companies. Since 1991, I have worked in various positions within PSEG. I have spent most of my career contributing to the development and implementation of PSE&G electric and gas rates, revenue requirements, pricing and corporate planning with over 20 years of direct experience in Northeastern retail and wholesale electric and gas markets.

As Sr. Director of the Corporate Rates and Revenue Requirements department, I have submitted pre-filed direct cost recovery testimony as well as oral testimony to the New Jersey Board of Public Utilities and the New Jersey Office of Administrative Law for base rate cases, as well as a number of clauses including infrastructure investments, renewable energy, and energy efficiency programs. A list of my prior testimonies can be found on pages 3 and 4 of this document. I have also contributed to other filings including unbundling electric rates and Off-Tariff Rate Agreements. I have had a leadership role in various economic analyses, asset valuations, rate design, pricing efforts and cost of service studies.

I am an active member of the American Gas Association's Rate and Strategic Issues Committee, the Edison Electric Institute's Rates and Regulatory Affairs Committee and the New Jersey Utility Association (NJUA) Finance and Regulatory Committee.

EDUCATIONAL BACKGROUND

I hold a B.S. in Mechanical Engineering from Worcester Polytechnic Institute and an MBA from Fairleigh Dickinson University.

LIST OF PRIOR TESTIMONIES

Company	Utility	Docket	Testimony	Date	Case / Topic
Public Service Electric & Gas Company	E/G	ER18070688 and GR18070689	written	Jul-18	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER18060681	written	Jul-18	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR18060675	written	Jun-18	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	EO18060629 - GO18060630	written	Jun-18	Energy Strong II / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	G	GR18060605	written	Jun-18	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER18030231	written	Mar-18	Tax Cuts and Job Acts of 2017
Public Service Electric & Gas Company	E/G	GR18020093	written	Feb-18	Remediation Adjustment Charge-RAC 25
Public Service Electric & Gas Company	E/G	ER18010029 and GR18010030	written	Jan-18	Base Rate Proceeding / Cost of Service & Rate Design
Public Service Electric & Gas Company	E	ER17101027	written	Sep-17	Energy Strong / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	G	GR17070776	written	Jul-17	Gas System Modernization Program II (GSMP II)
Public Service Electric & Gas Company	G	GR17070775	written	Jul-17	Gas System Modernization Program (GSMP) - Second Roll-In
Public Service Electric & Gas Company	G	GR17060720	written	Jul-17	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER17070724 - GR17070725	written	Jul-17	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER17070723	written	Jul-17	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR17060593	written	Jun-17	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER17030324 - GR17030325	written	Mar-17	Energy Strong / Revenue Requirements & Rate Design - Sixth Roll-in
Public Service Electric & Gas Company	E/G	EO14080897	written	Mar-17	Energy Efficiency 2017 Program
Public Service Electric & Gas Company	E	ER17020136	written	Feb-17	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E/G	GR16111064	written	Nov-16	Remediation Adjustment Charge-RAC 24
Public Service Electric & Gas Company	E	ER16090918	written	Sep-16	Energy Strong / Revenue Requirements & Rate Design - Fifth Roll-in
Public Service Electric & Gas Company	E	EO16080788	written	Aug-16	Construction of Mason St Substation
Public Service Electric & Gas Company	E	ER16080785	written	Aug-16	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	G	GR16070711	written	Jul-16	Gas System Modernization Program (GSMP) - First Roll-In
Public Service Electric & Gas Company	G	GR16070617	written	Jul-16	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER16070613 - GR16070614	written	Jul-16	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER16070616	written	Jul-16	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR16060484	written	Jun-16	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	EO16050412	written	May-16	Solar 4 All Extension II (S4Allext II) / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	E/G	ER16030272 - GR16030273	written	Mar-16	Energy Strong / Revenue Requirements & Rate Design - Fourth Roll-in
Public Service Electric & Gas Company	E/G	GR15111294	written	Nov-15	Remediation Adjustment Charge-RAC 23
Public Service Electric & Gas Company	E	ER15101180	written	Sep-15	Energy Strong / Revenue Requirements & Rate Design - Third Roll-in
Public Service Electric & Gas Company	E/G	ER15070757-GR15070758	written	Jul-15	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER15060754	written	Jul-15	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR15060748	written	Jul-15	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR15060646	written	Jun-15	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER15050558	written	May-15	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E	ER15050558	written	May-15	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER15030389-GR15030390	written	Mar-15	Energy Strong / Revenue Requirements & Rate Design - Second Roll-in
Public Service Electric & Gas Company	G	GR15030272	written	Feb-15	Gas System Modernization Program (GSMP)
Public Service Electric & Gas Company	E/G	GR14121411	written	Dec-14	Remediation Adjustment Charge-RAC 22
Public Service Electric & Gas Company	E/G	ER14091074	written	Sep-14	Energy Strong / Revenue Requirements & Rate Design - First Roll-in
Public Service Electric & Gas Company	E/G	EO14080897	written	Aug-14	EEE Ext II
Public Service Electric & Gas Company	G	ER14070656	written	Jul-14	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER14070651-GR14070652	written	Jul-14	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER14070650	written	Jul-14	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR14050511	written	May-14	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	GR14040375	written	Apr-14	Remediation Adjustment Charge-RAC 21
Public Service Electric & Gas Company	E/G	ER13070603-GR13070604	written	Jun-13	Green Programs Recovery Charge (GPRC)-Including DR, EEE, EEE Ext, CA, S4All, SLII / Cost Recovery
Public Service Electric & Gas Company	E	ER13070605	written	Jul-13	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR13070615	written	Jun-13	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR13060445	written	May-13	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	EO13020155-GO13020156	written/oral	Mar-13	Energy Strong / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	G	GO12030188	written/oral	Mar-13	Appliance Service / Tariff Support
Public Service Electric & Gas Company	E	ER12070599	written	Jul-12	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER12070606-GR12070605	written	Jul-12	RGGI Recovery Charges (RRC)-Including DR, EEE, EEE Ext, CA, S4All, SLII / Cost Recovery
Public Service Electric & Gas Company	E	EO12080721	written/oral	Jul-12	Solar Loan III (SLIII) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E	EO12080721	written/oral	Jul-12	Solar 4 All Extension(S4Allext) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	G	GR12060489	written	Jun-12	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	G	GR12060583	written	Jun-12	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER12030207	written	Mar-12	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E	ER12030207	written	Mar-12	Non-Utility Generation Charge (NGC) / Cost Recovery

LIST OF PRIOR TESTIMONIES

Company	Utility	Docket	Testimony	Date	Case / Topic
Public Service Electric & Gas Company	G	GR11060338	written	Jun-11	Margin Adjustment Charge (MAC) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	G	GR11060395	written	Jun-11	Weather Normalization Charge / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E	EO11010030	written	Jan-11	Economic Energy Efficiency Extension (EEEext) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E/G	ER10100737	written	Oct-10	RGGI Recovery Charges (RRC)-Including DR, EEE, CA, S4All, SLII / Cost Recovery
Public Service Electric & Gas Company	E/G	ER10080550	written	Aug-10	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E	ER10080550	written	Aug-10	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	GR09050422	written/oral	Mar-10	Base Rate Proceeding / Cost of Service & Rate Design
Public Service Electric & Gas Company	E	ER10030220	written	Mar-10	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	E	EO09030249	written	Mar-09	Solar Loan II(SLII) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E/G	EO09010056	written	Feb-09	Economic Energy Efficiency(EEE) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E	EO09020125	written	Feb-09	Solar 4 All (S4All) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E	EO08080544	written	Aug-08	Demand Response (DR) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E/G	ER10100737	written	Jun-08	Carbon Abatement (CA) / Revenue Requirements & Rate Design - Program Approval

PSE&G CEF Energy Cloud (EC)
Weighted Average Cost of Capital (WACC)

Schedule SS-CEF-EC-1

	Percent	Embedded Cost	Weighted Cost	Pre-Tax Weighted Cost	Pre-Tax Weighted Cost	After Tax Weighted Cost
Other Capital	45.53%	3.96%	1.80%	1.0000	1.80%	
Customer Deposits	0.47%	0.87%	0.00%	1.0000	0.00%	
Sub-total	46.00%		1.81%		1.81%	1.30%
Preferred Stock	0.00%	0.00%	0.00%	1.3910	0.00%	0.00%
Common Equity	54.00%	10.30%	5.56%	1.3910	7.74%	5.56%
Total	100.00%		7.37%		9.54%	6.86%

Federal Income Tax	21.00%
State NJ Business Incm Tax	9.00%
Tax Rate	28.1100%

PSE&G CEF Energy Cloud (EC)
Electric Forecasted Annual Roll-in Calculation

Schedule SS-CEF-EC-2

in ($000)

Sample Calculation	Roll-in 1	Roll-in 2	Roll-in 3	Roll-in 4	Roll-in 5	Roll-in 6
Rate Effective Date						
Plant In Service as of Date	2/28/2021	2/28/2022	8/31/2022	2/28/2023	8/31/2023	3/31/2024
Rate Base Balance as of Date	5/31/2021	5/31/2022	11/30/2022	5/31/2023	11/30/2023	6/30/2024

RATE BASE CALCULATION

		Roll-in 1	**Roll-in 2**	**Roll-in 3**	**Roll-in 4**	**Roll-in 5**	**Roll-in 6**	**Total**	
1	Gross Plant	$69,919	$86,532	$90,630	$90,965	$91,635	$93,690	**$523,369**	= ln 16
2	Accumulated Depreciation	$6,921	$13,612	$19,622	$19,801	$20,153	$20,119	**$100,229**	= ln 19
3	Net Plant	$76,840	$100,144	$110,252	$110,766	$111,788	$113,809	**$623,598**	= ln 1 + ln 2
4	Accumulated Deferred Taxes	-$6,698	-$7,072	-$7,714	-$8,886	-$7,884	-$9,341	**-$47,596**	= See "Dep-" Wkps Row 724
5	Rate Base	$70,143	$93,071	$102,538	$101,879	$103,903	$104,468	**$576,002**	= ln 3 + ln 4
6	Rate of Return - After Tax (Schedule WACC)	6.86%	6.86%	6.86%	6.86%	6.86%	6.86%	**6.86%**	See Schedule SS-CEF-EC-1
7	Return Requirement (After Tax)	$4,812	$6,384	$7,034	$6,989	$7,127	$7,166	**$39,512**	= ln 5 * ln 6
8	Depreciation Exp, net	$3,280	$3,382	$3,291	$3,299	$3,316	$3,383	**$19,951**	= ln 25
9	Tax Adjustment	$0	$0	$0	$0	$0	$0	**$0**	N/A
10	Revenue Factor	1.3944	1.3944	1.3944	1.3944	1.3944	1.3944	**1.3944**	
11	**Total Revenue Requirement**	**$11,282**	**$13,618**	**$14,397**	**$14,346**	**$14,563**	**$14,709**	**$82,915**	= (ln 7 + ln 8 + ln 9) * ln 10

SUPPORT

Gross Plant

		Roll-in 1	Roll-in 2	Roll-in 3	Roll-in 4	Roll-in 5	Roll-in 6	Total	
12	Plant in-service	$69,919	$86,532	$90,630	$90,965	$91,635	$93,690	**$523,369**	= See "Dep-" Wkp Row 702
13	CWIP Transferred into Service	$0	$0	$0	$0	$0	$0	**$0**	= See "Dep-" Wkp Row 703
14	AFUDC on CWIP Transferred Into Service - Debt	$0	$0	$0	$0	$0	$0	**$0**	= See "Dep-" Wkp Row 704
15	AFUDC on CWIP Transferred Into Service - Equity	$0	$0	$0	$0	$0	$0	**$0**	= See "Dep-" Wkp Row 705
16	**Total Gross Plant**	**$69,919**	**$86,532**	**$90,630**	**$90,965**	**$91,635**	**$93,690**	**$523,369**	= ln 12 + ln 13 + ln 14 + ln 15

Accumulated Depreciation

		Roll-in 1	Roll-in 2	Roll-in 3	Roll-in 4	Roll-in 5	Roll-in 6	Total	
17	Accumulated Depreciation	-$5,138	-$2,934	-$2,289	-$2,293	-$2,306	-$2,661	**-$17,622**	= See "Dep-" Wkp Row 711
18	Cost of Removal	$12,059	$16,546	$21,911	$22,094	$22,459	$22,781	**$117,850**	= See "Dep-" Wkp Row 706
19	**Net Accumulated Depreciation**	**$6,921**	**$13,612**	**$19,622**	**$19,801**	**$20,153**	**$20,119**	**$100,229**	= ln 17 + ln 18

Depreciation Expense (Net of Tax)

		Roll-in 1	Roll-in 2	Roll-in 3	Roll-in 4	Roll-in 5	Roll-in 6	Total	
20	Depreciable Plant (xAFUDC-E)	$69,919	$86,532	$90,630	$90,965	$91,635	$93,690	**$523,369**	= ln 12 + ln 13 + ln 14
21	AFUDC-E	$0	$0	$0	$0	$0	$0	**$0**	= ln 15
22	Depreciation Rate	6.52%	5.44%	5.05%	5.05%	5.03%	5.02%		= See "Dep-" Wkp
23	Depreciation Expense	$4,562.00	$4,704.36	$4,578.05	$4,589.63	$4,612.79	$4,705.18	**$27,752**	= (ln 20 + ln 21) * ln 22
24	Tax @28.11%	$1,282.38	$1,322.39	$1,286.89	$1,290.15	$1,296.66	$1,322.63	**$7,801**	= ln 20 * ln 22 * Tax Rate
25	Depreciation Expense (Net of Tax)	**$3,279.62**	**$3,381.96**	**$3,291.16**	**$3,299.49**	**$3,316.14**	**$3,382.55**	**$19,951**	= ln 23 - ln 24

PSE&G CEF Energy Cloud (EC)
Rate Design and Tariff Rate Summary

Table 1 - Cost Allocation % Calculation

	GLP	RS	Total
Meter Cost %	16.00%	84.00%	
Meter Count %	12.48%	87.52%	
Meter Material - $	39,752,980	208,776,961	248,529,942
All Other Costs - $	58,919,068	413,290,484	472,209,552
Total Costs - $	98,672,049	622,067,445	720,739,494
Cost Allocation %	13.69%	86.31%	100.00%
Cost Allocation % - Rounded	13.70%	86.30%	100.00%

Table 2 - Interclass Revenue Allocation

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	
$000	Energy Cloud Cost Allocation	6/1/21	6/1/22	12/1/22	6/1/23	12/1/23	7/1/24	Total
Rev Req		11,282	13,618	14,397	14,346	14,563	14,709	82,915
RS	85.9%	9,689	11,695	12,364	12,319	12,506	12,632	71,204
RHS	0.4%	48	58	61	61	62	62	352
GLP	13.7%	1,546	1,866	1,972	1,965	1,995	2,015	11,359
	Input	[Rev Req] * (1)	[Rev Req] * (1)	[Rev Req] * (1)	[Rev Req] * (1)	[Rev Req] * (1)	[Rev Req] * (1)	

Table 3 - Service Charge Rates - w/o SUT

	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
$	2016 Cost of Service			Rates Effective						
Rate Class	Revenue Requirement	# of Customers	Monthly Service Charge	Current	6/1/21	6/1/22	12/1/22	6/1/23	12/1/23	7/1/24
RS	168,598,866	1,868,649	7.52	2.27	2.70	3.22	3.77	4.32	4.88	5.44
RHS	1,004,626	9,233	9.07	2.27	2.70	3.22	3.77	4.32	4.88	5.44
GLP	40,322,907	256,703	13.09	3.96	4.46	5.07	5.71	6.35	7.00	7.65
					= ((2) * 1,000) / (10) / 12) + (12)	= ((3) * 1,000) / (10) / 12) + (13)	= ((4) * 1,000) / (10) / 12) + (14)	= ((5) * 1,000) / (10) / 12) + (15)	= ((6) * 1,000) / (10) / 12) + (16)	= ((7) * 1,000) / (10) / 12) + (17)

Table 4 - Service Charge Rates - w/ SUT

Tax Rate = 6.625%

$	Rates Effective						
Rate Class	Current	6/1/21	6/1/22	12/1/22	6/1/23	12/1/23	7/1/24
RS	2.42	2.88	3.43	4.02	4.61	5.20	5.80
RHS	2.42	2.88	3.43	4.02	4.61	5.20	5.80
GLP	4.22	4.76	5.41	6.09	6.77	7.46	8.16
	(11) * (1 + [Tax Rate])	(12) * (1 + [Tax Rate])	(13) * (1 + [Tax Rate])	(14) * (1 + [Tax Rate])	(15) * (1 + [Tax Rate])	(16) * (1 + [Tax Rate])	(17) * (1 + [Tax Rate])

PSE&G CLEAN ENERGY FUTURE - ENERGY CLOUD PROGRAM
Electric Annual Bill Impact Summary

Incremental Typical Annual Bill Impacts
By Rate Class

Rate Class	If Your Annual kWhr Use Is:	Current Bill ($)	Roll-In Date 6/1/2021	6/1/2022	12/1/2022	6/1/2023	12/1/2023	7/1/2024	End of Program Customer Bill
RS	7,200	1,233.72	5.52	6.60	7.08	7.08	7.08	7.20	1,274.28
RHS	13,804	1,875.04	5.52	6.60	7.08	7.08	7.08	7.20	1,915.60
GLP	29,767	4,831.20	6.48	7.80	8.16	8.16	8.28	8.40	4,878.48

Incremental Annual Percent Change From Current Typical Annual Bill
By Rate Class[1]

Rate Class	If Your Annual kWhr Use Is:	Current Bill ($)	Roll-In Date 6/1/2021	6/1/2022	12/1/2022	6/1/2023	12/1/2023	7/1/2024	Total Percent Change from Current Bill
RS	7,200	1,233.72	0.45%	0.53%	0.57%	0.57%	0.57%	0.58%	3.27%
RHS	13,804	1,875.04	0.29%	0.35%	0.38%	0.38%	0.38%	0.38%	2.16%
GLP	29,767	4,831.20	0.13%	0.16%	0.17%	0.17%	0.17%	0.17%	0.97%

PSE&G CLEAN ENERGY FUTURE - ENERGY CLOUD PROGRAM
Electric Annual Bill Impact Summary

Cumulative Typical Annual Bill Impacts
By Rate Class

Rate Class	If Your Annual kWhr Use Is:	Current Bill ($)	Roll-In Date 6/1/2021	6/1/2022	12/1/2022	6/1/2023	12/1/2023	7/1/2024
RS	7,200	1,233.72	5.52	12.12	19.20	26.28	33.36	40.56
RHS	13,804	1,875.04	5.52	12.12	19.20	26.28	33.36	40.56
GLP	29,767	4,831.20	6.48	14.28	22.44	30.60	38.88	47.28

Cumulative Percent Changes From Current Typical Annual Bill
By Rate Class

Rate Class	If Your Annual kWhr Use Is:	Current Bill ($)	Roll-In Date 6/1/2021	6/1/2022	12/1/2022	6/1/2023	12/1/2023	7/1/2024
RS	7,200	1,233.72	0.45%	0.98%	1.56%	2.13%	2.70%	3.29%
RHS	13,804	1,875.04	0.29%	0.65%	1.02%	1.40%	1.78%	2.16%
GLP	29,767	4,831.20	0.13%	0.30%	0.46%	0.63%	0.80%	0.98%

[1]Total percent change may not tie to the cumulative percent due to rounding

NOTICE TO PUBLIC SERVICE ELECTRIC AND GAS COMPANY ELECRIC CUSTOMERS

In the Matter of the Petition of Public Service Electric and Gas Company for Approval of its Clean Energy Future - Energy Cloud Program ("CEF-EC Program")

Notice of Filing and Notice of Public Hearings

BPU Docket No.: XXXXXXXXXX

TAKE NOTICE that Public Service Electric and Gas Company ("Public Service" or the "Company") filed a Petition with the New Jersey Board of Public Utilities ("Board" or "BPU") in September 2018 requesting approval to upgrade the Company's meter infrastructure through the establishment of a Clean Energy Future – Energy Cloud Program ("CEF-EC Program" or the "Program"). The CEF-EC Program will deploy advanced metering infrastructure ("AMI") throughout the Company's electric service territory over a five-year period beginning in 2019. PSE&G seeks BPU approval to commit up to $721 million in direct investment over a period of approximately five years.

In conjunction with the implementation of the Program, PSE&G will seek Board approval to recover in base rates the revenue increases associated with the capital investment costs of the CEF-EC program. While the Company is not seeking an increase at this time, PSE&G is seeking authority to recover a return on and return of its investments through semi-annual adjustments to its base rates beginning on June 1, 2021. The Company estimates that the rate change for electric rates effective June 1, 2021 would increase rates by approximately $11.3 million. This rate change is only an estimate at this time and is subject to change.

For illustrative purposes, the June 1, 2021 estimated base rates including New Jersey Sales and Use Tax ("SUT") for residential Rate Schedules RS is shown in Table #1. Table #2 provides customers with the approximate effect of the proposed change in annual bills relating to the Program, if approved by the Board, effective June 1, 2021. The annual percentage increase applicable to specific customers will vary according to the applicable rate schedule and the level of the customer's usage.

Under the Company's proposal, a residential electric customer using 750 kilowatt-hours per month during the summer months and 7,200 kilowatt-hours on an annual basis would see an initial increase in the annual bill from $1,233.72 to $1,239.24, or $5.52 or approximately 0.45%. The approximate effect of the proposed base rate change on typical electric residential monthly bills, if approved by the Board, is illustrated in Table #4.

Based upon current projections and assuming full implementation of the complete Program as proposed, the anticipated incremental annual bill impact for the typical residential electric customer using 7,200 kilowatt-hours annually would be: $5.52 or approximately 0.45% effective 6/1/2021; $6.60 or approximately 0.53% effective 6/1/2022; $7.08 or approximately 0.57% effective 12/1/2022; $7.08 or approximately 0.57% effective 6/1/2023; $7.08 or approximately 0.57% effective 12/1/2023; $7.20 or approximately 0.58% effective 7/1/2024.

Tables #4 & #5 provide customers with the estimated incremental and cumulative rate impacts of the Program to typical and class average customers for Residential and, Commercial classes, respectively. The annual percentage increase applicable to specific customers will vary according to the applicable rate schedule and the level of the customer's usage. It is anticipated that the Company will make semi-annual filings each year of the Program to request the Board's approval to implement that Program Year's revenue requests. The Board's decisions may increase or decrease the percentages shown.

Any rate adjustments with resulting changes in bill impacts found by the Board to be just and reasonable as a result of the Company's filing may be modified and/or allocated by the Board in accordance with the provisions of N.J.S.A 48:2-21 and for other good and legally sufficient reasons to any class or classes of customers of the Company. Therefore, the described charges may increase or decrease based upon the Board's decision.

Copies of the Company's filing are available for review by the public at the Company's Customer Service Centers, online at the PSEG website at http://www.pseg.com/pseandgfilings and at the Board of Public Utilities at 44 South Clinton Avenue, Seventh Floor, Trenton, New Jersey 08625-0350.

The following dates, times and locations for public hearings have been scheduled on the Company's filing so that members of the public may present their views. Information provided at the public hearings will become part of the record of this case and will be considered by the Board in making its decision.

Date 1, 2018	Date 2, 2018	Date 3, 2018
Time 1	Time 2	Time 3
Location 1	Location 2	Location 3
Location 1 Overflow	Location 2 Overflow	Location 3 Overflow
Room 1	Room 2	Room 3
Room 1 Overflow	Room 2 Overflow	Room 3 Overflow
Address 1	Address 2	Address 3
City 1, New Jersey Zip 1	City 2, New Jersey Zip 2	City 3, New Jersey Zip 3

In order to encourage full participation in this opportunity for public comment, please submit any requests for needed accommodations, such as interpreters, listening devices or mobility assistance, no less than 48 hours prior to the above hearings to the Board's Secretary at the following address.

Customers may also file written comments with the Secretary of the Board of Public Utilities at 44 South Clinton Avenue, Third Floor, Suite 314, P.O. Box 350, Trenton, New Jersey 08625-0350 ATTN: Secretary Aida Camacho-Welch, whether or not they attend the public hearings. To review PSE&G's rate filing, visit http://www.pseg.com/pseandgfilings.

Table # 1
BASE RATES
For RS, RHS and GLP Customers
Rates if Effective June 1, 2021 for Electric

Rate Schedule			Base Rates	
			Charges in Effect June 1, 2018 Including SUT	Estimated Charges Including SUT
Electric				
RS	Service Charge	per month	$2.42	$2.88
RHS	Service Charge	per month	2.42	2.88
GLP	Service Charge	per month	4.22	4.76

Table #2
Proposed Percentage Change in Annual Bills
By Customer Class for Electric Service
For Rates if Effective June 1, 2021

Electric		
	Rate Class	Percent Change
Residential	RS	0.45%
Residential Heating	RHS	0.29
General Lighting & Power	GLP	0.13

The percent increases noted above are based upon September 8, 2018 Delivery Rates, the applicable Basic Generation Service (BGS) charges, and assumes that customers receive commodity service from Public Service Electric and Gas Company.

Table #3
Residential Electric Service for Rates if Effective June 1, 2021

If Your Annual kWh Use Is:	And Your Monthly Summer kWh Use Is:	Then Your Present Monthly Summer Bill (1) Would Be:	And Your Proposed Monthly Summer Bill (2) Would Be:	Your Monthly Summer Bill Increase Would Be:	And Your Monthly Summer Percent Increase Would Be:
1,920	200	$35.83	$36.29	$0.46	1.28%
4,320	450	77.60	78.06	0.46	0.59
7,200	750	129.79	130.25	0.46	0.35
7,800	803	139.37	139.83	0.46	0.33
13,160	1,360	240.12	240.58	0.46	0.19

(1) Based upon Delivery Rates and Basic Generation Service Residential Small Commercial Pricing (BGS-RSCP) charges in effect September 8, 2018 and assumes that the customer receives BGS-RSCP service from Public Service Electric and Gas Company.
(2) Same as (1) except includes the proposed change for the CEF-EC Program.

Table # 4
Residential Electric Service
Projected Incremental Percent Change
From Annual Bills Effective June 1, 2018

Rate Class	Forecasted % Increase 6/1/2021	Forecasted % Increase 6/1/2022	Forecasted % Increase 12/1/2022	Forecasted % Increase 6/1/2023	Forecasted % Increase 12/1/2023	Forecasted % Increase 7/1/2024
RS	0.45%	0.53%	0.57%	0.57%	0.57%	0.58%
RHS	0.29%	0.35%	0.38%	0.38%	0.38%	0.38%
GLP	0.13%	0.16%	0.17%	0.17%	0.17%	0.17%

The percent increases noted above are based upon Delivery Rates in effect September 8, 2018 and the applicable Basic Generation Service (BGS) charges and assuming customers receive commodity service from Public Service Electric and Gas Company. It is anticipated that the Company will make semi-annual filings each year of the Program to request the Board's approval to implement that Program Year's revenue requests. The Board's decisions may increase or decrease the percentages shown above.

Table # 5
Electric Service
Projected Cumulative Percent Change
From Annual Bills Effective June 1, 2018

Rate Class	Forecasted % Increase 6/1/2021	Forecasted % Increase 6/1/2022	Forecasted % Increase 12/1/2022	Forecasted % Increase 6/1/2023	Forecasted % Increase 12/1/2023	Forecasted % Increase 7/1/2024
RS	0.45%	0.98%	1.56%	2.13%	2.70%	3.29%
RHS	0.29%	0.65%	1.02%	1.40%	1.78%	2.16%
GLP	0.13%	0.30%	0.46%	0.63%	0.80%	0.98%

The percent increases noted above are based upon Delivery Rates in effect September 8, 2018 and the applicable Basic Generation Service (BGS) charges and assuming customers receive commodity service from Public Service Electric and Gas Company. It is anticipated that the Company will make semi-annual filings each year of the Program to request the Board's approval to implement that Program Year's revenue requests. The Board's decisions may increase or decrease the percentages shown above. The cumulative totals in Table #7 may not agree to Table #6 due to rounding.

Matthew M. Weissman, Esq.
General State Regulatory Counsel
PUBLIC SERVICE ELECTRIC AND GAS COMPANY