Direct Testimony of

Paul Sutherland, Senior Advisor

Saber Partners, LLC

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DIRECT TESTIMONY OF PAUL R. SUTHERLAND, CPUC R.17-06-026

Q. Please state your name and business address.

A. Paul R. Sutherland, Saber Partners, LLC (Saber or Saber Partners), 44 Wall Street, New York, New York 10005.

Q. By whom are you employed and what is your position?

A. I am with Saber Partners, LLC, and serve as a Senior Advisor.

Q. Please describe your duties and responsibilities in that position.

A. My responsibilities with Saber include work in data management, financial modeling, financial analysis, issuance cost auditing, deal structuring, pricing analysis with respect to relative value and review of issuance advice letters, all on behalf of public utility commission clients. I have performed these functions while advising the following regulatory bodies regarding utility securitizations: Public Utility Commission of Texas, West Virginia Public Service Commission, New Jersey Board of Public Utilities, Florida Public Service Commission and the Wisconsin Public Service Commission.

Q. Please describe your educational background and professional experience.

A. I have a bachelor's degree in electrical engineering from Cornell University. I also have a master's degree in business administration from the University of Chicago.

I began working with Florida Power & Light Company (FPL) in 1976 doing economic analysis of new energy technologies in the Research and Development (R&D) Department. After several years, I moved to the Finance Department as a Financial Analyst. Over the next 20 years I held various positions, including Coordinator of Financial Systems, Manager of Corporate Finance, Manager of Financial Analysis and Forecasting, and Assistant Treasurer of both the utility and FPL Group Capital. Before leaving FPL in 1998, I was Director of Finance, Accounting & Systems for the FPL Energy Marketing and Trading Division. During my time with FPL, I testified as an expert witness on cost of capital and financial integrity. I have also taught classes on economic decision-

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making and on quality improvement. It was during this time (1989) that FPL became the first non-Japanese company to win the Deming Prize for Total Quality Management.

In 2000, after a year as adjunct professor of mathematics at Palm Beach Atlantic College, I joined Saber Partners, LLC as a Senior Managing Director. I have been associated with Saber Partners since that time in various roles, including my current position as Senior Advisor. I have taken part in 13 investor-owned utility securitization financings that raised over $9.5 billion in capital for 8 different utilities.

Q. Can you provide some of your background and experience with utility financings while you were at FPL?

A. Yes. While at FPL, as Manager of Corporate Finance and Assistant Treasurer, I helped FPL complete over $2 billion of debt and equity financings in the public capital markets. FPL executed both competitive and negotiated securities offering transactions. FPL was also among the first to issue long-term variable rate tax-exempt debt that could be (and was) later converted to a fixed rate. Part of my job was to prepare and, along with the Treasurer and Chief Financial Officer (CFO), deliver rating agency presentations to support the credit ratings from the three major rating agencies.

Q. Are you sponsoring any exhibits in this case?

A. Yes, I am sponsoring:

Exhibit A, Glossary

Exhibit B, Flow diagram of transaction participants and cash flow

Exhibit C, List of securitization transactions to date

Exhibit D, Credit rating chart

Exhibits E. i, SEC view on securitization of regulatory assets

E.ii, Accountants Handbook §4-12 Securitization of Regulatory Assets

E. iii, FASB Accounting Standards Codification Topic 860-10-55-8

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E.iv, SEC Letter dated 9/19/2007

Exhibit F.i.a, Duke Energy Florida (DEF) Prospectus cover

F.ii, Prospectus pp. 4-20: Prospectus Summary with highlighted sections showing risk mitigation factors

F.iii, Prospectus pp. 99-102: WAL and Yield Considerations - Sensitivity Analysis

Exhibit G, Various uses for securitization in past transactions

Exhibit H, Securitization 4-tranche structure: PG&E all UOG & ex-fossil, SCE all UOG

Exhibit I, Traditional revenue requirement: PG&E all UOG & ex-fossil, SCE all UOG

Exhibit J, Levelized vs. declining revenue requirements: PG&E all UOG & ex-fossil, SCE all UOG

Exhibit K, Savings dependent upon more than just interest rates: PG&E and SCE

Exhibit L.i and ii, Upfront and Ongoing costs of securitization

Exhibit M, Summary of potential savings with UOG securitization: PG&E and SCE

Exhibit N, VEPP Inc. Article from *The Wall Street Journal*

Exhibit O, PSNH Use of Proceeds

Exhibit P, Hypothetical PPA buydown

Exhibit Q, Sources of Data Used

Q. Whom do you represent in this proceeding?

A. I represent Saber Partners, LLC, who has been hired by the California Community Choice Association (CalCCA) to provide an independent evaluation and opinion as to the benefits, costs, risks, and rewards for PCG and EIX customers and shareholders of using securitization as part of the California Commission's Rulemaking 17-06-026, to "consider alternatives to the Power Charge Indifference Adjustment."

Q. What is the purpose of your testimony?

A. The purpose is to analyze the potential customer savings from using the financing technique known as securitization, should the California State legislature authorize it and Pacific Gas and Electric Company (PG&E) and /or Southern California Edison Company (SCE), together

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with the California Public Utilities Commission (CPUC or the Commission) and other stakeholders, agree to pursue it.

I will provide an overview of utility securitization financing to explain what it is, how it differs from other types of debt offerings, and why it is advantageous to the ratepayers to use it in applications such as with the financing of utility owned generation (UOG) and possibly also to finance buydowns of high-priced power purchase agreements (PPAs). The main purpose of my testimony is to analyze the utility securitization applications in question and discuss quantitative and qualitative benefits that could be achieved, both for the ratepayer and the utility. Included in this testimony as Exhibit A is a glossary of terms to help in understanding some technical financial terms in the language of the financial markets.

Q. What is securitization?

A. In general, securitization is a process by which a pool of assets which generate a cash flow, such as loans, credit card balances or other receivables, is used as collateral for a bond offering. The pledged asset generates a flow of cash that is used to pay principal and interest on the bonds.

To give buyers of the bonds comfort that only they have a claim on the pledged assets and that they will be repaid, the pledged assets are transferred to a special purpose legal entity which is protected from any credit problems of the utility. This is known as a "bankruptcy remote" or "ring fenced" entity and is often called a special or limited purpose entity (SPE). This means it has a strictly limited purpose i.e., to own the pledged assets and to pay the principal and interest on its bonds. When setting up this "special purpose entity", the entire right, title and interest in the pledged assets is transferred at a "fair market value" to the SPE. The SPE pledges these assets to secure the bonds, and the cash flows from those pledged assets are used to pay principal and interest on the bonds. Thus, the risk to the bondholder is just the risk associated with the cash flows from the pledged assets in the SPE. The pledged assets can be physical (such as plant and equipment) or financial (such as a loan receivable or the right to some other revenue). Exhibit B

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is a flowchart that shows the flow of funds in a securitization transaction while the bonds are outstanding.

Q. What is securitization in the context of electric utilities?

A. For investor-owned electric utilities, securitization is a specific legislatively enabled and regulatory approved process of issuing highly-rated securities through special purpose, bankruptcy remote/ring fenced entities to raise capital for purposes such as compensating the utility for stranded assets or storm-related expenditures. It is a direct borrowing on the utility's customer rate base in its distribution territory without involving the utility's balance sheet for credit purposes or comingling with the utility's other creditors. Because of this, the bonds have often been called ratepayer-backed bonds or ratepayer obligation charge (ROC) bonds and even rate reduction bonds (RRB), among other terms.

Bond repayment is secured through collection by the utility of a Commission-approved and periodically adjusted dedicated rate component and not a pool of receivables. The SPE and the securities it issues are perceived to carry much less risk than standard utility corporate debt and are therefore attractive to investors at a lower cost to the utility. Mr. Fichera's testimony details the legislative and regulatory framework critical to a successful securitization and one that protects ratepayer interests. Ratepayers benefit because the carrying costs of this debt are much less than the costs that would be incurred using traditional utility financing methods of debt and equity, which is often called the utility's "weighted average cost of capital" (WACC). For the utility, securitization increases cash flow and achieves a lower cost of capital than traditional means of raising capital. Electric utility securitization has been used by investor-owned utilities as a taxable debt financing tool at least 64 times since 1997. Those transactions are listed in my Exhibit C.

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Q. What are the benefits of using the type of securitization financing that you have described in the current situation?

A. In the case of PG&E and SCE, securitization offers an opportunity to reduce the costs of resources in the utilities' PCIA (Power Charge Indifference Adjustment) portfolios for all customers responsible for paying the PCIA, including bundled, community choice aggregation (CCA) and direct access (DA) customers. The non-bypassable securitized charge also might improve cost transparency and facilitate collection of PCIA from CCA and DA customers.

This testimony contemplates two possible uses of securitization within the PCIA-Eligible portfolios:

1. Utility-owned generation (UOG); and
2. High-cost power purchase agreements (PPAs).

Securitization would reduce the cost of financing UOG assets by reducing the utility's weighted average cost of capital to a much lower securitized debt-only interest rate. This tool could also be used to provide funding to buy down the prices of high-priced contracts for the purchase of energy, again taking advantage of differences between a project owner's capital costs and securitized debt interest rates.

Securitization offers added benefits beyond the differences in the cost of capital. Because securitization reduces utility income, it also reduces income taxes, including income-based state franchise taxes, as well as revenue-based local franchise fees. In addition, securitization levelizes the debt carrying charges, shifting more costs into later years. This creates a net present value (NPV) benefit.

As discussed below, securitization of UOG assets and possibly of PPA buydown costs would deliver significant value to all PG&E and SCE ratepayers responsible for the PCIA, including CCA and DA customers. Securitization of the PCIA UOG rate base could potentially produce NPV savings to PG&E customers from $1.3 to $1.6 billion, and to SCE customers approximately $589 million. Additional savings may also be achievable through the

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securitization of PPA buydowns. My testimony provides an illustrative buydown example using an average price reduction of 13 cent per KWH for 2,000 GWH/year of purchased power, which, when netted against a securitization cost of 9.4 cents/KWH results in a net savings of 3.6 cents/KWH in the first year. Such a restructuring could result in NPV savings to bundled, CCA and DA ratepayers of $449 million. Whichever scenario the Commission, utilities and stakeholders elect to pursue, securitization will deliver value to ratepayers, the utility, and the state in reducing procurement costs and, if consistent with state goals, continuing to transition to a more competitive environment.

Q. How are securitization bonds structured to attract private capital?

A. Securitization bonds usually have multiple maturities such as 3, 5, 10, 15 or 20 years. These maturities are also known as "tranches" or a "series," part of a larger composite issue. Rather than pay bonds all at once at the maturity (as is done in traditional utility finance, known as "bullet" or single maturity bonds), the securitization bonds pay off over time like a home mortgage. They pay a mix of principal and interest over a number of years. The schedule of principal payments is known as the amortization schedule. In the past, many utilities and corporations issued bonds with a form of an amortization schedule in them. They were known as "sinking fund" bonds which paid down over time. State and Local governments use this form of financing in a slightly different way through the issuance of many different bonds maturing sequentially. These are known as serial bonds.

Q. When do ratepayers repay the bonds?

A. With utility securitization financing, each tranche will have its own amortization schedule and interest rate. There will be a specific date when each bond begins to repay principal and interest, and a subsequent date when the next principal payment will be made on that bond. Interest will be paid on those dates as well, and the amount of interest paid will be calculated on the amount that is outstanding i.e., has not already been repaid. These principal dates are known as the "Scheduled Maturities." When one averages those scheduled dates with the dollar amount of the

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payments over the time it takes to receive all payments for a specific tranche or series, one gets the "weighted average life" of the tranche (WAL). By "life" we are referring to the time the bonds remain active and outstanding.

Q. Is there another type of maturity associated with these bonds other than the scheduled maturity?

A. Yes. There is a "legal final maturity" associated with tranche. This is the date by which the investor must receive the principal amount that was scheduled to be paid or it will be declared an event of default and investors will be given legal rights to seek recovery of their investment.

Q. Why is there a time difference between a "Scheduled Maturity" and a "Legal Final Maturity"?

A. The only cash available to pay the principal and interest on the bonds comes from the collection of the charge on ratepayer bills based on their consumption of electricity. The timing of the receipt of that cash is uncertain and could be affected by many factors influencing the consumption of electricity. Consequently, there is some time built into the structure of the bond to address any volatility in collections.

Q. How do investors perceive the quality or creditworthiness of utility securitization bonds compared to that of traditional utility debt?

A. Investors generally rely upon nationally recognized independent credit rating agencies, such as Moody's, Standard & Poor's and Fitch to evaluate the financial and legal characteristics of the SPE and the bonds. These agencies give an opinion as to the likelihood of receiving principal and interest on the bonds when it is legally due, not when it is scheduled to be paid. They evaluate or rate this likelihood on a scale from highly likely to be repaid on time to unlikely to be paid on time, on the legal maturity dates.

As a short cut for investors to judge the credit of one bond to another, the rating agencies assign letters to their opinions. This scale is known as a "ratings scale" and is usually denoted by letters such as AAA for the best and strongest credit to CCC for a very weak credit. Exhibit D

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shows the rating scales for the 3 major credit rating agencies. The likelihood of repayment is also known as "default risk," or what the likelihood is that an issuer will not pay when an amount is legally due, and defaults on its obligation. With one exception, all utility securitization debt since 1997 has been rated AAA by the major rating agencies. This is not the case with other types of securitization debt. Moreover, no investor owned utility securitization bond has ever been downgraded or even placed on a watch list for possible downgrade, even through the bankruptcy of PG&E and Montana Power and the 2008-09 financial crisis.

Q. What is a common name for securities in a securitization?

A. When the pledged assets are fixed and there are limited intangible rights or a specific pool of payment obligations from identified obligors, they are commonly referred to as asset-backed securities (ABS). Common ABS types include those backed by corporate loans, credit card receivables or auto loan receivables. The cash flows are usually fixed or limited to a specific identified pool of assets.

Q. Is this a correct description for utility securitization?

A. No, for the reasons described below, it is not. However, utility securitization bonds compete for investment capital from ABS investors and corporate bond investors. It is important for investors to know the similarities and differences in the bonds to achieve the lowest cost of capital in the market

Q. What rating do most ABS receive?

A. The rating that ABS receive always depends on the quality and amount of the pledged assets (receivables), the legal structure, and a host of other factors. Generally, the higher the rating, the lower the interest rate on the ABS. Issuers borrowing against the pledged assets try to structure the transaction to receive a high rating, such as AAA, to make the most efficient use of the pledged assets as collateral for the ABS.

However, there are also lower rated ABS, and even within a single SPE there might be two or more classes of securities with different rights to the collateral in the pool, and thus different

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ratings. The market for ABS is very complex, and there are a wide variety of credit issues and concerns with ABS. ABS with AAA ratings and comparable terms to maturity might be valued very differently by investors.

Q. How is utility securitization debt different from ABS?

A. When properly structured, utility securitization bonds are not ABS. They are not backed by a pool of receivables or a finite set of cashflows. While they do have some things in common, there are several important differences that make utility securitization debt more secure than even the best AAA-rated ABS or corporate bonds.

The common feature of a utility securitization with ABS is that both use an SPE to issue bonds based on a cash flow from the pledged assets in the SPE and a separate "servicer" to collect the cash flows from the pledged assets and distribute to investors. Some terminology describing the SPE is also the same.

However, on the critical features relating to the credit-worthiness of the bonds – the payment of principal and interest when due - utility securitizations are decidedly not like what are commonly referred to as "asset-backed securities." For example, as described in Mr. Fichera's testimony in more detail, in each state where utility securitization bonds have been issued, they were issued under specific enabling state legislation. The legislation created a new type of intangible property which consists of the right to impose, adjust, bill and collect amounts from virtually all electric customers in a given service territory.

Thus, securitized utility bonds are backed by an enforceable regulatory right, not by an enforceable contract right or pool of receivables or other assets. Important differences in investors' rights and remedies arise by reason of this difference in the nature of the rights that back securitized utility bonds. For this reason, the Office of Chief Accountant of the U.S. Securities and Exchange Commission (SEC) has directed that the property that is pledged to support securitized utility bonds should not be treated as a "financial asset" and that the securitized utility bonds themselves not be treated as "asset-backed securities" for financial

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reporting purposes. See Exhibits E.i-iv.

Q. What is SEC Regulation AB?

A. Regulation AB (17 CFR § 229.1100, et. seq.,) is the SEC regulation setting forth general rules for the sale of ABS through public offerings. Any publicly offered securitized utility bonds issued for the benefit of PG&E or SCE would need to comply with Regulation AB if the securitized utility bonds are treated as "asset-backed securities."

Q. Do you expect the SEC to treat securitized utility bonds issued for the benefit of PG&E and/or SCE, as summarized in Mr. Abramson's, Mr. Schoenblum's and Mr. Fichera's testimony, as "asset-backed securities" for purposes of Regulation AB?

A. No. Mr. Abramson, Mr. Schoenblum and Mr. Fichera recommend that financing orders providing for the issuance of securitized utility bonds authorize those bonds to be issued in one or more series over a period of time. The SEC defines the term "asset-backed security" to exclude securities issued by an entity that is authorized to issue more than one series of bonds over time. SPEs formed to issue securitized utility bonds for West Virginia utilities (MP Funding and PE Funding) were authorized to issue more than one series of bonds over time and were treated as corporate bond issuers. This allowed the bonds to appeal to the broadest possible investor base and achieve a lower interest rate.

The SEC's Office of Chief Counsel, Division of Corporation Finance confirmed that these bonds were not asset-backed securities. In an interpretive and "no-action" letter dated September 19, 2007, they stated: "Based on the facts presented, it is the Division's view that MP Funding and PE Funding are not asset-backed issues and the Bonds are not asset-backed securities within the meaning of Item 1101 of Regulation AB." A copy of that September 19, 2007 letter is attached to this testimony as Exhibit E.iv. Saber Partners, as Financial Advisor to the West Virginia Public Service Commission, participated actively in requesting and receiving that September 19, 2007 interpretive and no-action letter. Therefore, I expect the SEC Division of

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Corporation Finance will *not* treat securitized utility bonds issued for the benefit of PG&E and/or SCE as "asset-backed securities" for purposes of Regulation AB. Consequently, the bonds will appeal to the broadest possible market and could achieve the lowest possible cost to ratepayers.

Q. How have these principles been applied in the prospectuses of publicly offered securitized utility bonds?

A. The most recent publicly offered securitized utility bonds were $1,294,290,000 of nuclear asset recovery Series A Bonds issued on June 15, 2016 by Duke Energy Florida Project Finance, LLC ("DEF Project Finance") for the benefit of Duke Energy Florida, LLC ("DEF" or "depositor"). Excerpts from the prospectus for those bonds (the "2016 DEF Prospectus") are attached to this testimony as Exhibits F.i, F.ii and F.iii. Consistent with the SEC's September 19, 2007 letter, the cover page of that prospectus stated clearly: "*The Series A Bonds are corporate securities. Neither the depositor nor DEF Project Finance is an asset-backed issuer and the Series A Bonds are not asset-backed securities as defined by the SEC governing regulations Item 1101 of Regulation AB.*"[1]

Q. Since investor perceptions of the credit affect the interest rate on the bonds, how do utility securitization bonds compare to ABS or traditional utility securities in terms of creditworthiness?

A. Several characteristics of utility securitization debt make it more creditworthy and less risky than ABS debt and traditional utility debt. If investors are properly educated, this should the bonds to achieve lower interest rates from investors.

[1] *See also* 2016 DEF Prospectus page 4: "We are not an asset-backed issuer, and the Series A Bonds are not asset-backed securities within the meaning of Item 1101(c) of Regulation AB… We may issue additional nuclear asset-recovery bonds, but only as authorized under the financing order or under a new and separate financing order."; 2016 DEF Prospectus page 13: "The bonds are corporate securities and are not asset-backed securities as defined by the SEC in governing regulations Item 1101 of Regulation AB."; 2016 DEF Prospectus page 37: "The nuclear asset-recovery property is not a receivable, and the principal collateral securing the bonds is not a pool of receivables, nor are the bonds asset-backed securities within the meaning of Item 1101 of Regulation AB."

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First, the obligation to pay the securitized charge arises from state legislation and regulation, and not by contract. As summarized above, the SEC Office of Chief Accountant has declared this difference to be sufficiently material to give rise to different accounting treatment for ABS than for securitized utility debt.

Second, as explained on page 13 of the 2016 DEF Prospectus Summary in my Exhibit F.ii, the obligation of the ratepayers is joint and several.

Q How are customers responsible for paying securitization charges on a joint and several basis?

A. This is a critical distinguishing factor. If some customers no longer receive electric transmission or distribution service from DEF or its successors or, for whatever reason, fail to pay the nuclear asset-recovery charges, other customers that continue to consume electric transmission or distribution service from DEF or its successors would be responsible for paying nuclear asset-recovery charges. Any delinquencies or under-collections in one customer rate class will be considered in the application of the true-up mechanism to adjust the nuclear asset-recovery charge for all customers of DEF.

This is to be distinguished from a credit card or home mortgage backed ABS where if one customer does not pay his or her credit card bill or home mortgage for whatever reason, the remaining customers in the pool of credit card receivables or home mortgages do not become responsible for the shortfall. Consequently, this means that investors in conventional ABS debt might not receive all their principal and interest. This is a material difference.

Finally, as described in more detail in Mr. Fichera's testimony, the securitized charge is non-bypassable. This means that if the ratepayer takes delivery of electricity by means of wires owned by the utility or its successor, there is no way the ratepayer can avoid the charge. The financing order issued by the regulator is irrevocable and therefore cannot be revisited at any time during the life of the bonds. This makes it very important for the Commission to have a complete understanding of the transaction up front, which is a key reason for the Commission, when

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making irrevocable decisions, to have available experts and independent and experienced financial advisors to assist the Commission in discharging its duties.

Q. Have issuers tried to quantify the risk of default of securitized utility bonds?

A. Yes. The 2016 DEF Prospectus addresses this issue under the heading "Sensitivity to Credit Risk," on pages 100-102, Exhibit F.iii. Various stress tests were performed on the bond structure using a model of forecasted utility revenues. The conclusion was "For an event of default to occur with respect to any such payment due under the indenture, the forecast variance for the forecast period leading up to such payment would need to be greater than minus 60%, or more than 16 standard deviations from the forecast variance mean."

Q. What do investors look at when evaluating a bond besides the interest rate and the likelihood of repayment?

A. Two investor concerns are related to uncertainty regarding the timing of principal repayment. Investors ask, first, "Will I get my investment back sooner than expected?" and second, "Will I get my investment back later than expected?" These two types of uncertainty are known as "prepayment risk" and "extension risk," respectively.

Usually a bond has a specific schedule of principal and interest payments. Investors are lending money (by buying the bonds), and they want to earn a return over a specific time period. However, bonds could be sold with the issuer's option (referred to as a "call option") to pay back the investor sooner than scheduled. The existence of such a "call" option results in prepayment risk. The bond issuers might want to pay back sooner for a variety of legal or managerial reasons, but usually it is because interest rates are lower, so the issuers can sell a new bond at a lower rate to pay off the older bond at a higher rate. Investors who get their money back sooner might consider it a good thing, but not if they cannot reinvest at the same or better rate compared to what they were previously getting. The capital markets usually extract a premium (higher interest rate) for this "prepayment risk."

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Q. Do AAA-rated ABS bonds typically have prepayment risk?

A. Yes. AAA-rated ABS bonds typically have prepayment risk. Many AAA-rated ABS issuers flow through substantially all payments received in respect of the specific collateralized pool of financial assets, such as receivables and home mortgages, even though this might force investors to accept repayment of their principal investment earlier than scheduled and expected when they initially bought the security. Conversely, most utility securitization bonds do not have prepayment risk. For example, page 99 of the 2016 DEF Prospectus in my Exhibit F.iii. states: "No prepayment is permitted."

Q. You also mentioned "extension risk." What is that?

A. Rating agencies' stress-case studies of ABS often show there is significant risk that even AAA-rated ABS will return investors' principal significantly later than scheduled. As I mentioned above, this is commonly called "extension risk." Investors usually require additional yield (higher interest rate) to compensate for any material extension risk. We suggest that the proposed utility owned generation bonds be structured such that any "extension risk" will be insignificant. Indeed, in many stress-case scenarios we have seen that this risk is statistically insignificant. That cannot be said of most ABS bonds because of the nature of the pledged assets and how the ABS bonds are structured.

As I have said, securitized utility bonds represent a joint and several liability of all ratepayers collectively. Securitized bonds are structured with a true-up mechanism contained in the financing order that adjusts the charge on consumers to whatever level is necessary to meet the schedule of principal and interest payments. This mechanism requires the securitized charge to be adjusted periodically pursuant to a pre-approved formula, usually semi-annually or more frequently if desired, to ensure the principal and interest is paid according to schedule. For example, if there were an unexpected decline in energy sales for some period, the charge per KWH could be increased subsequently to make up for the earlier shortfall. Thus, the true up mechanism is very responsive to unforeseen changes in collections. In other words, it is a robust

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adjustment mechanism to collect from electricity ratepayers whatever is needed to meet the bond's cash flow obligations.

The most important way to capture value from investors is to describe accurately and precisely the characteristics of the utility securitization in the disclosure documents accompanying the sale of the bonds to investors. The SEC registration statements pursuant to which a number of prior securitized utility bonds have been offered have provided detail about the unusual and superior credit quality of the securities. I have highlighted in the DEF Prospectus Summary (Exhibit F.ii) in particular, certain sections discussing aspects that mitigate against risk to the investor and help lower the interest rate on the bonds.

Q. Was extension risk discussed in detail in the 2016 DEF Prospectus?

A. Yes. Page 100 of the 2016 DEF Prospectus stated:

"The weighted average life table below illustrates whether there is risk to bondholders of a material weighted average life extension of each WAL designation.

> *"The table shows changes from the expected weighted average life of each WAL designation of bonds assuming actual future electricity consumption and related charge collections varies from DEF's forecast of future electricity consumption and related charge collections (the forecast variance) of 5% (1.3 standard deviations from the forecast variance mean) or 15% (4.0 standard deviations from the forecast variance mean) during each payment period.*
>
> *The weighted average life table below illustrates that the aggregate payment of principal of and interest on the bonds and the timing of such payments are not expected to change materially over the life of the bonds, based on the assumptions we have made."*

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Series A Bonds	Expected Weighted Average Life (yrs)	Effect on Weighted Average Life (Rounded*) of Change in Forecast Variance: −5% (1.3 Standard Deviations from Forecast Variance Mean) Weighted Average Life (yrs)	Effect on Weighted Average Life (Rounded*) of Change in Forecast Variance: −15% (4.0 Standard Deviations from Forecast Variance Mean) Weighted Average Life (yrs)
Series A 2018	2.0	2.0	2.0
Series A 2021	5.0	5.0	5.1
Series A 2026	10.0	10.0	10.0
Series A 2032	15.2	15.2	15.3
Series A 2035	18.7	18.7	18.8

* Number is rounded to 1/10th of one year

Q. Do you expect it will possible for similar statements about extension risk to be included in the prospectuses pursuant to which the securitized utility bonds proposed to be issued for PG&E and SCE are issued?

A. Yes.

Q. How would California utilities, if they wanted to, issue utility securitization debt?

A. Mr. Fichera's testimony details the steps needed for successfully pursuing securitization in California to achieve the benefits that I will describe below. He describes the type of enabling legislation needed, the irrevocable financing order that would be issued by the Commission as well as other issues need to protect ratepayer interests in the sale of the bonds to private investors.

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Q. Would securitization of the unrecovered costs of UOG assets prevent PG&E or SCE from divesting those UOG assets in the future?

A. No. Securitized utility bonds will be secured by a pledge of the intangible property right that represents the right to impose, adjust, bill and collect the securitization charge. That will be entirely separate from the UOG assets themselves. The UOG assets will not be pledged to secure the securitization charge. Consequently, securitization would not impair the ability of PG&E or SCE to divest their UOG assets.

Q. How would cash received upon the future sale of UOG assets be treated so that ratepayers would not be adversely affected by a divestiture?

A. Cash received from any future sale of UOG assets would be tracked in a balancing account and used to adjust other rates and charges imposed on customers, including CCA and DA customers.

Q. Can you give an example of how a balancing account has been used for such purposes in connection with prior California utility securitized bonds?

A. Yes. Mr. Abramson's testimony describes securitized Energy Recovery Bonds issued in 2005 to refinance a bankruptcy-related regulatory asset of PG&E. CPUC Decision No. 03-12-035 initially established that regulatory asset in the amount of $3.0 billion, but provided that the amount of that regulatory asset was to be reduced to the extent PG&E in the future received energy supplier refunds arising in connection with the 2000-2011 energy crisis. In its Financing Order (Decision No. 04-11-015) authorizing the issuance of Energy Recovery Bonds to refinance the unrecovered balance of this PG&E regulatory asset, the CPUC ordered that an Energy Recovery Balancing Account (ERBBA) be established for a variety of purposes, and that amounts credited to the ERBBA were to be returned to customers through a separate ERBBA charge. The ERBBA charge was not pledged to secure the Energy Recovery Bonds. One of those purposes was to track future energy supplier refunds. The Financing Order states: "These energy supplier refunds will be credited to the ERBBA, earn short-term interest while in the ERBBA, and be

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refunded to consumers via the next annual adjustment to the ERBBA charge." Similarly, amounts received from any future divestiture of UOG assets should be returned to the utility's customers by means of adjustments to other rates and charges.

Q. What are the roles of the different participants in a typical utility securitization?

A. The easiest way to understand the various roles is to look at the flowchart in my Exhibit B. The electric utility sponsors the transaction, sells the intangible asset to the SPE and, at least initially, services the bonds by billing the customer, collecting the charge and remitting the funds to the trustee. The trustee pays the stated interest and principal to the bondholder. The Commission issues the financing order and checks proposed true-up adjustments to the securitization charge for mathematical correctness. The electric retail customer (including CCA and DA customers) pays the charge and bears all the financial burden associated with the debt once the bonds are sold.

The activities of the SPE should be restricted by the financing documents so that it cannot engage in any activities unrelated to this financing without receiving a rating confirmation from the rating agencies. The SPE will be owned by the sponsoring utility and will be capitalized by the utility such that its equity capital is 0.5 percent of the SPE's securitized bonds.

Q. How have utility securitizations been used in the past?

A. Investor owned utilities, together with state legislatures and public utilities commissions, have used utility securitization bonds to fund, among other things, stranded costs from utility deregulation, environmental control costs and, in the case of Florida, in 2006, and most recently, New Orleans in 2015, storm recovery costs. See Exhibit G for more examples.

Q. How are ratepayer benefits achieved with utility securitization?

A. The securitization of unrecovered costs of UOG assets will benefit ratepayers in multiple ways. First, and most importantly, there will be economic benefits to ratepayers. Significant savings occur when securitized bonds are used to replace a combination of conventional utility

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debt and equity financing. It is effectively off-balance-sheet and non-recourse to the utility. The utility is fully-protected. This means that the utility can finance the asset or expense in question with nearly 100% debt rather than its normal capital mix of about 50% debt and 50% equity, without any impairment of its credit structure. The ratepayer savings are even greater for a utility like PG&E that has a lower credit rating.

There are several reasons why utility securitization saves money. First, the cost of equity is much higher than the cost of debt. A 5% cost of traditional long-term debt and an 11% cost of equity are typical values in today's environment. In addition, savings occur by the avoidance of income taxes that would otherwise have to be paid on the equity return. These savings accrue directly to the ratepayers in the form of lower overall rates than would otherwise be levied.

Another source of savings comes from pricing these securitized ratepayer-backed bonds in the capital markets commensurate with their extremely high credit quality. In general, the better the credit rating, the lower the interest cost. By separating the operating utility from the SPE issuer of the bonds and isolating the cash flow, the credit associated with securitized ratepayer-backed bonds will be evaluated by investors as independent of the sponsoring utility and independent of the traditional debt of the utility. Traditional utility debt has numerous risks associated with its repayment. Those risks will not be present in connection with securitized ratepayer-backed bonds.

The savings commensurate with top-quality credit is not automatic. Not all "AAA" rated bonds are sold or trade at the same interest rate or yield. There are a number of steps that are required at the time the securitized ratepayer-backed bonds are structured, marketed, and priced to achieve the lowest cost available in the market and to capture the full economic value of the unique government guarantees embodied in the legislation and the irrevocable nature of the financing order.

In addition, by using the "best practices" identified in the testimony of Mr. Fichera, the CPUC and the utilities can work to maximize benefits and to improve ratepayer protections.

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Additional ratepayer NPV savings occur due to the levelizing of revenue requirements, which I shall discuss shortly.

Q. Why is a "lowest cost" standard important?

A. Since the proceeds of a bond issuance are cash dollars, the appropriate standard in reviewing benefits is the "lowest cost" standard. Issuers want to raise the maximum amount of dollars at the lowest possible cost. Note, however, that underwriters have a vested interest in urging the use of a standard of "reasonable cost" because "reasonable" covers a range of outcomes. For any large, long-term financing, that range might represent millions or tens of millions of dollars in extra costs. One might choose to use a reasonable costs standard to reimburse a doctor, where there are differences in both the type and quality of care. However, one dollar has the same quality as another dollar, and a bond issuer should want the most dollars for the lowest cost. Mr. Fichera's testimony discusses this issue in more detail.

Q. What are the benefits to the utility that you briefly mentioned earlier?

A. As described above, securitization of the unrecovered costs of UOG assets can have several benefits to the utilities. When structured correctly, this financing method will increase cash flow for the utilities and allow for debt to be issued at a superior credit rating. In addition, when state policies promote retail competition and the utility elects to transition out of procurement, it allows the utility to make this transition in a cost-effective manner.

Securitization offers greater potential benefits to PG&E in light of recent downgrades of its debt. The restoration and strengthening of PG&E as an investment grade company may be considered vital to the company's future ability to service its customers. The securitization of unrecovered costs of UOG will provide PG&E access to capital at a lower cost than they might otherwise be able to obtain. PG&E may then use such capital either in response to storm damage or wild fire response or to pay down higher cost debt, thereby potentially causing its credit rating to increase as its debt-to-equity ratio decreases. See the testimony of Mr. Abramson for a more detailed discussion of potential benefits to the utility.

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Q. Can you describe the analysis you performed to quantify the potential ratepayer benefits?

A. Yes. As noted previously, if a securitization strategy were undertaken, cash realized by the utility could be used to either pay down other, more expensive, utility debt, or to free up debt and equity capital for other important projects, such as planned capital expenditures, emergency funds or extraordinary expenses. The utility's revenue requirement would decrease, resulting in savings to ratepayers. Significant value could be found in each, or all, of the potential applications of securitization discussed in this testimony.

Securitizing all or a portion of the existing UOG rate base would reduce financing costs to all ratepayers, including bundled customers and CCA/DA customers. As discussed in the overview of Chapter 3, CalCCA proposes securitization of all unrecovered costs of UOG remaining in the PCIA-Eligible portfolio. I performed an analysis that shows that if all of PG&E's unrecovered costs of UOG were securitized, this strategy could remove up to an NPV of $1.6 billion in costs from the PG&E portfolio of generation assets. Exhibit H shows what the structure of such a securitization might look like assuming interest rates as they exist today and assuming the financing as of the end of this year. Exhibit I shows the same assets financed at PG&E's current cost of capital using traditional ratemaking and asset depreciation and debt amortization. While PG&E's weighted average cost of capital is 7.69% (or about 9.75% pre-tax), the cost of the securitization financing has an overall cost rate of just 3.91% (for a WAL of 11.7 years), and there is no gross-up for income taxes since there is no equity financing involved. The difference between these two financing scenarios amounts to about $1.6 billion on an NPV basis.

Page 2 of Exhibit H shows the structure for securitization of PG&E's UOG excluding fossil generation, while page 2 of Exhibit I shows the same assets financed using traditional capital structure. The NPV benefit in this case amounts to $1.3 billion.

I also performed an analysis that shows that if all of SCE's unrecovered costs of non-CAM UOG were securitized, this strategy could remove up to an NPV of $589 million in costs from the

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SCE portfolio of generation assets. Page 3 of Exhibit H shows what the structure of such a securitization might look like assuming interest rates as they exist today and assuming the financing as of the end of this year. Page 3 of Exhibit I shows the same assets financed at SCE's current cost of capital using traditional ratemaking and asset depreciation and debt amortization. While SCE's weighted average cost of capital is 7.61% (or about 9.53% pre-tax), the cost of the securitization financing has an overall cost rate of just 4.07% (for a slightly longer WAL of 14.94 years), and there is no gross-up for income taxes since there is no equity financing involved. The difference between these two financing scenarios amounts to about $589 million on an NPV basis.

Q. Does the use of securitization financing affect the timeframe over which the UOG assets are paid for by the ratepayers?

A. Yes, not so much in the number of years over which the ratepayer pays, but rather in the amount the ratepayer pays in the earlier years versus the later years. Exhibit J shows the annual revenue requirements for each of the two different financing approaches. Traditional ratemaking requires the ratepayer to pay much more in the early years of an asset's useful life and much less in the later years. Securitization financing allows the ratepayer to pay a levelized amount throughout the life of the assets in question. By levelizing the payments that are financed with inexpensive debt rather than front-end loading revenue requirements, the NPV savings, when discounted at the utility cost of capital (7.69% and 7.61% for PG&E and SCE, respectively), are increased substantially.

Q. Are all utility securitizations structured in this same way to levelize revenue requirements?

A. Yes, in a general sense, although the details may differ slightly. Some deals are structured to levelize the total dollar revenue requirement. Others are structured to levelize annual payments of principal. Others are structured to levelize the securitization charge in cents per kilowatt hour. This can be done by taking into account a projection of KWH sales growth over the

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life of the bonds.

Q. Did your analysis attempt to explain which aspects of a utility securitization account for most of the savings that you have projected?

A. Yes. Exhibit K shows how much of the total securitization savings result from different characteristics of the financing structure and the economic environment in which it is used. There are three main sources of savings and several smaller sources. Biggest of all is the difference in cost between utility equity and securitization debt. While PG&E's authorized cost of equity is 10.25%, which accounts for 52% of its capital structure, the securitization debt at current levels would bear an interest rate of only about 3.91%. This difference accounts for about 43% of the overall savings in the case of PG&E. In the case of SCE, the utility's authorized cost of equity is 10.3% and accounts for 48% of the capital structure. SCE also has 9% of its capitalization in preferred stock costing 5.82% (compared to just 1% preferred stock for PG&E). Securitized debt in the SCE 4-tranche securitization structure would cost only about 4.07%, as I mentioned earlier. In the case of SCE, more expensive equity accounts for about ~~47%~~ 45% of the savings.

The second largest contributor to savings is the difference due to income-based taxes which burden the equity portion of the capital structure. When the Federal tax rate of 21% is combined with the 8.84% rate for California income-based franchise taxes, the effective composite income tax rate is 28%. With securitization financing, there are no income-based taxes. This difference accounts for about 29% of the $1.6 billion savings in the case of PG&E and ~~33%~~ 32% of the savings in the case of SCE.

The third contributor to savings is the levelization that I discussed previously. Levelizing the revenue requirements when securitizing PG&E's utility owned generation creates about 23% of the $1.6 billion total NPV savings that I have estimated for PG&E ratepayers. For SCE, levelization accounts for just ~~15%~~ 18% of the $589 million total NPV savings. The reason for the difference between the two utilities is because in PG&E's case, the securitization scenario shifts a greater proportion of the revenue requirements into the future, particularly due to the relatively

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short remaining useful life of PG&E's nuclear assets.

In addition to these major factors, there are savings from the fact that AAA rated securitization debt is less expensive than A+ or BBB+ rated utility debt (4% of the savings) and the fact that revenue-based fees, such as local franchise fees would be slightly less (1% of the savings).

Q. Are there any transaction fees associated with securitization financing that are greater than in traditional utility financing?

A. Yes, there are, due to the complexity and structured way that these financings work. In Exhibits I.i and ii, I show what upfront and ongoing transaction costs have been in some recent securitization transactions. In my analysis, I have assumed that upfront costs, together with the NPV of ongoing costs, would be about 2% of the principal amount.

This is a conservative estimate for several reasons. First, in the case of the Duke Energy Florida transaction, which had a $1.294 billion principal amount, the NPV of transaction costs was just over 2% of principal. Both upfront and ongoing costs have a variable component that would be less for larger transactions. My example assumes a principal amount of up to $4.65 billion in the case of PG&E and $1.48 billion for SCE, so that even if the securitizations were done in two transactions for PG&E, the transaction costs would probably be 2% or less in each case. Secondly, financing orders generally include a provision that requires the utility to reduce other electric utility rates and charges to reflect the amount by which any of the bond servicing fee paid to the utility is in excess of its marginal or incremental cost to perform the service.

Q. What other cases for using securitization to refinance the unrecovered costs of UOG did you examine?

A. Using the same methodology, I have described, I looked at securitization for PG&E excluding fossil generation. That is how I arrived at a range of possible NPV savings of $1.3 to $1.6 billion for PG&E ratepayers. In the case of SCE, it is my understanding that there is no non-CAM fossil generation, so I only looked at the single UOG case for SCE. I have summarized the

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results of my analysis in Exhibit M.

Q. Are there any other material differences, besides the amount of potential savings, between the cases you examined for PG&E and those you analyzed for SCE?

A. Yes. The case I looked at for SCE assumed a final expected maturity for the securitization bonds of 25 years rather than the 20 years for PG&E. I extended the final maturities because the remaining lives for the UOG assets were longer in the case of the SCE generation. There is some uncertainty associated with this assumption, since 20 years is the longest securitization that has been done to date. Still, I believe it is achievable with no severe penalty in terms of a significantly higher interest rate or marketability. There is a very strong demand for these types of securities in today's market.

Q. How would costs associated with capital additions be affected by securitization of unrecovered costs of existing UOG plant assets?

A. If securitization is limited to refinancing unrecovered costs of existing UOG assets, the costs of future capital additions would not be affected. That future rate base would be depreciated using traditional ratemaking, subject to the utility rate of return, and recovered in rates from customers, rather than through a dedicated rate component. Chapter 3 addresses ongoing PCIA cost responsibility for uneconomic capital additions.

It is possible that near-term capital additions for which costs are fairly certain at the time of the securitization could be included in the initial UOG securitization. Furthermore, major subsequent capital additions could be financed with a future securitization if amounts were large enough to warrant. For example, Monongahela Power and Potomac Edison (subsidiaries of Allegheny Energy Inc. at the time through MP Funding and PE Funding subsidiaries) financed flue gas desulfurization equipment with a securitization in 2007 and then followed up with securitization of additional costs for that equipment in 2009. Saber Partners oversaw both transactions as Financial Advisor to the West Virginia Public Service Commission.

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Q. Are there any other potential uses for securitization in PG&E and SCE that you have examined?

A. Yes, another way to utilize securitization is to finance the buydown of existing PPA contracts. Some of these contracts were set with prices as high as 18 cents/KWH or more at a time when electric rates were expected to escalate sharply. That was before the growth of availability of shale oil and the advent of fracking that has produced an abundance of natural gas. These are generally long-term contracts (some for 20-25 years) at set prices and quantities. The prices of many of these contracts may now exceed current and expected future market prices. While many of these PPAs have supported the state's goal of increasing reliance on renewable resources or increased reliability, they tie the utility to long term, high-cost contracts. There may be circumstances in which some of the generators that are selling power to the utilities under these PPAs may be willing to enter into voluntary and mutually agreeable reductions in the PPA prices in exchange for an up-front cash payment, i.e. a buydown.

Securitization, through the same process described above, could be used to reduce the costs of one or more of these contracts. As discussed in Chapter 3, the utility might conduct a "reverse RFO" seeking voluntary proposals from sellers/generators for a buydown of the contract price. As CalCCA has proposed the process, the price reduction would be the only change, and all other terms of the PPA would remain in effect. The likely delta between a securitized debt interest rate and the counterparties' internal discount rates (likely based principally on their own cost of capital) presents another opportunity for ratepayer savings. In this case, legislation would grant the Commission specific authority to administer a PPA buydown program, potentially with conditions, and to fund the buydowns using a dedicated rate component through a securitization financing.

Q. Has securitized debt been issued for this purpose in the past?

A. Using securitization to fund PPA buydowns was proposed in Vermont in 1999. Exhibit N is an article from *The Wall Street Journal* that discusses the attempt of the Vermont Electric

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Power Producers (VEPP Inc.) to buydown PPAs that where priced as high as 17.5 cents/KWH. Saber Partners served as Financial Advisor to VEPP, Inc. and assisted in achieving the enabling state legislation. The state of Vermont passed the enabling legislation to authorize securitization for this purpose. After much study and negotiation, VEPP Inc. was never able to execute the buydowns at prices that created ratepayer savings, and securitized bonds, therefore, were not issued.

However, in April 2001 and again in January 2002, Public Service Company of New Hampshire issued Rate Reduction Bonds (another term for securitization debt) for reducing its capitalization and buying down high-cost PPAs. Exhibit O shows cover information and Use of Proceeds language from those two transactions.

Q. Have you been able to quantify the potential savings that could result from using securitization to buydown high-cost PPAs?

A. While I did not examine the utilities' PPAs to determine how much each utility might be able to save through buydowns, I was able to model a hypothetical case that convinced me that savings may be possible. Exhibit P shows that under certain circumstances, in particular even when the PPA counterparty has a relatively low cost of capital (assumed to be 6.5% in my example) and when a long maturity securitization is used, some savings are possible. However, without examining the PPA portfolios, I would expect the savings to be neither as large nor as certain as they would be in the case of refinancing the unrecovered cost of UOG. As shown in Exhibit P, the NPV savings amount to just 17% of the principal amount of securitized bonds issued to buydown PPAs compared to 34% to ~~41%~~ 40% in the case of securitized bonds issued to refinance the unrecovered costs of UOG (see Exhibit M). To a large extent, this is because PPAs are already structured to levelize revenue requirements, so there is little or no added benefit from the levelization in the securitization structure. Some of the NPV benefit in my hypothetical case results from extending the term of the securitization debt beyond the term of the PPAs being bought down.

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Q. Is there greater uncertainty associated with using securitization to buydown high-cost PPAs as compared to using it to finance UOG?

A. Yes. The uncertainty arises because, unlike utility cost of capital, which is public information, it is not known what the PPA counterparty's cost of capital may be, and that is key to what the cost of a buydown will be. If the PPA counterparty has a high cost of capital, say 10% or so, the NPV of future prices (thus, the buydown lump sum payment demanded by the PPA owner/counterparty) would be smaller, making the buydown savings greater for the ratepayer. However, PPA projects are usually highly leveraged so that, while the cost of equity may be relatively high, it is a very small component of the PPA counterparty's cost of capital.

In addition, there are certain risks and/or circumstances that could make this type of securitization unattractive. For example, partial buydown or prepayment may not be a practical option under the terms of a power purchase agreement or could come with breakage costs and make-whole or prepayment penalties that may make a buy-down economically unsuitable for a particular contract. Also, there is some risk that the utility's relationships with its counterparty/generators could be damaged by the authorization of a potential buy-down. It is conceivable that the counterparty/generators are not cooperative and find the legislation oppressive in that it attempts to force their hand. However, a completely voluntary buydown program through, for example, something like a reverse auction, may mitigate some of that risk. Finally, the "opening up" of the transaction to renegotiation may not work in the utility's favor, as counterparties may attempt to renegotiate terms besides price to the detriment of the utility.

On the other hand, some counterparties might welcome a large cash buydown as an opportunity to raise significant amounts of cash without the need to resort to the capital markets. Therefore, securitized bonds issued to finance the buydown of high-priced PPAs might be a significant benefit to both ratepayers and PPA counterparties even if only counterparties to a few of the largest high cost PPAs opt into the program.

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Q. Would PG&E and SCE benefit from the use of securitization to buydown existing high-priced PPAs?

A. Yes. In recent years, credit rating agencies have begun to analyze long-term PPAs as though they were, in part, debt of the purchasing utility. This exposes PCG/PG&E and EIX/SCE to risk that the credit ratings on their other debt and equity securities will be reduced. This "debt equivalence" concern should be mitigated if PG&E's and SCE's annual payment obligations pursuant to their PPAs is materially reduced.

Q. Do you believe that the benefits you have quantified in your analyses are highly sensitive to potential changes in interest rates and might largely disappear if interest rates were to rise before a securitization financing could be brought to market?

A. No. My analysis indicates that the savings are not especially sensitive to the absolute level of interest rates. As my Exhibit K shows, the vast majority of benefits are due to

(1) levelization of revenue requirements,

(2) income-based taxes (Federal and state), and

(3) the spread between the cost of equity and the cost of securitization debt.

Consequently, if the cost of all types of capital rises in proportion, savings would not be significantly affected.

The greater risk is if the rates for securitization debt rise out of proportion to other rates. My calculations show that a 100 basis point (1%) increase in securitization interest rates with no change in the rest of the market (ceteris paribus) would decrease the $1.6 billion savings to PG&E ratepayers to a still significant $1.3 billion. Such a large distortion in the market for pricing securitization debt has only occurred once since such debt was first issued in 1997, and that happened during the financial crisis of 2008. I do not believe such a crisis is likely to happen again before PG&E and/or SCE have the chance to take advantage of this opportunity.

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Q. Can you summarize your recommendations?

A. Yes. I recommend that the parties to this proceeding seek State of California legislation authorizing the issuance of securitized utility bonds as described in my testimony and in the testimony of Mr. Fichera, Mr. Abramson and Mr. Schoenblum.

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EXHIBITS FOR

TESTIMONY OF PAUL SUTHERLAND

SABER PARTNERS, LLC

3/31/2018

EXHIBIT A

Glossary

Asset-backed security (ABS) - A debt security issued by a special purpose entity, the payment of which is backed by a physical asset (e.g., rail cars or airplanes) or a financial asset (e.g., a mortgage or the value of a portfolio of credit card receivables). At least for some purposes, utility securitization bonds are not technically asset-backed securities but often have been treated as such to the detriment of ratepayers.

Bankruptcy remote - An entity designed in such a way that (i) the likelihood of it going into bankruptcy is extremely small, and (ii) it would experience as little economic impact as possible in the event of a bankruptcy of other related legal entities.

Basis point (bp) - One one-hundredth of a percentage point. Often referred to in writing as "bp" (or "bps" in the plural).

Benchmark – When pricing a bond, the benchmark is a security with high price transparency that is agreed upon by all parties so that the yield on the new issue can be set relative to the yield on the benchmark. In that way, if yields in the market move after agreeing on the spread to benchmark but before final pricing, the parties do not have to renegotiate the final price/yield. A benchmark can also be a similar security used to determine relative value when talking to investors.

Maturity - The length of time until the issuer of a bond has to repay specified amounts to the lender / investor.

Final scheduled maturity date– The date by which it is expected that the final principal payment on a bond or on a group of substantially identical bonds will be made.

Final legal maturity date – The date by which, if the principal is not fully paid, the bonds will be considered to be in default. Usually, the final legal maturity date is one to two years after the final scheduled maturity date.

Irrevocable financing order - A finance order issued by state regulators that cannot be changed or revoked at a later date as long as the securitization bonds are outstanding, and which (i) segregates a specific component of the retail rate charge through the service territory, (ii) causes the right to receive this component to be treated as an interest in property that can be bought, sold or pledged (i.e. a receivable), (iii) authorizes the utility to sell such property to an SPE, (iv) authorizes the SPE to issue debt secured by such property, and (v) requires the utility which sold the property to use the proceeds of the sale for a specific purpose.

Relative value - The relationship between two securities. In pricing a new bond issue, for example, it is useful to compare the spread over swaps of the proposed bond yield to the spread over swaps of a AAA-rated US agency bond. If the two securities were judged equal in risk with identical terms (not callable, same WAL, etc.) but one had a higher spread, it would be said to have greater relative value.

Road show - A formal presentation to potential purchasers of a security, typically organized by underwriters with the involvement of the issuer and the financial advisor. A team sometimes travels around the U.S. to discuss the features of the security, resulting in the term "Road Show." Sometimes the team travels to foreign financial centers to make these presentations. In recent years, most Road Shows have been conducted using electronic media over the Internet, reducing or eliminating the need for travel.

Secondary market – The market in which stocks or bonds are traded after their initial issuance. When a bond trades at a substantially higher price (lower yield) in the secondary market immediately following its issuance, this is an indication that it was mispriced (priced too low) by the underwriters.

Securitization - The process by which a pool of assets, such as loan receivables, is used as a basis for issuing highly rated (often AAA) bonds. The pool of assets is created and transferred to a trust or, in a utility securitization, to a bankruptcy remote entity, known as a special purpose entity (SPE). The entire right, title and interest in the assets are transferred at a fair market value to the SPE. The SPE pledges the assets to secure the bonds and the cash flows from those assets are used to pay principal and interest on the bonds. Thus, the risk to the bondholder is just the risk associated with the cash flows from the assets in the SPE. The assets can be physical (such as plant and equipment) or intangible (such as a loan receivable or the right to some other revenue stream).

Special purpose entity (SPE) – A bankruptcy remote (see **bankruptcy remote** definition, above) legal entity set up for the express purpose of owning the right, title and interest in the assets used to secure the bonds and provide the cash flows to pay interest and principal on the bonds.

Spread – The difference between the market yields of different fixed income securities of similar maturities, expressed in basis points. If a Treasury bond maturing in seven years is trading to yield 3.87%, and a AAA-rated corporate bond is trading to yield 4.25%, the corporate bond is said to trade at a 38 basis point spread to the Treasury bond (4.25 – 3.87 = .38).

Spread is the easiest way to compare the cost of funds represented by different debt securities. Participants will refer to the spread "relative to Treasuries" or "relative to swaps" as the most meaningful measure used to compare a given debt security to the most liquid, most secure, and most easily available benchmark for a given maturity. Spreads are often referred to as either "tight" or "wide" to the benchmark. (See **Tight Spread/Wide Spread** definition below.)

Exhibit B

Participants in Electric Utility UOG/PPA Securitization Transaction

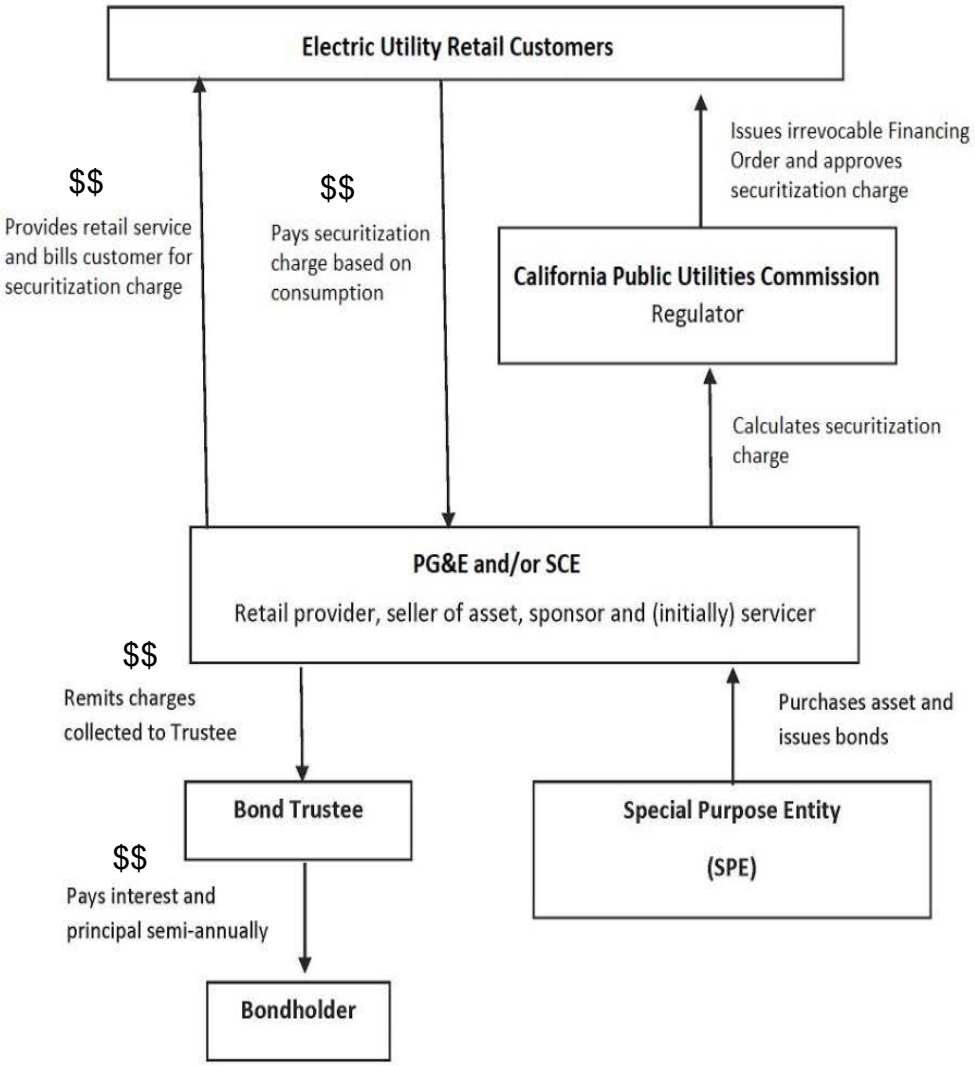


Exhibit C

Deal #	Issuer	Utility Beneficiary	Tranche	Amount	Weighted Average Life (years)
64	Duke Energy Florida Project Finance, LLC (6/15/2016)	Duke Energy Florida	A-1	$ 183,000,000	2.00
			A-2	$ 150,000,000	5.00
			A-3	$ 436,000,000	10.00
			A-4	$ 250,000,000	15.20
			A-5	$ 275,290,000	18.70
			Total	$ 1,294,290,000	11.14
63	Entergy New Orleans Storm Recovery Funding I, LLC (7/14/15)	Entergy New Orleans	A-1	$ 98,730,000	4.98
62	Department of Business, Economic Development, and Tourism (Hawaii) (11/04/2014)	Hawaiian Electric Co., Hawaii Electric Light Co., Maui Electric Co	A-1	$ 50,000,000	3.05
			A-2	$ 100,000,000	10.21
			Total	$ 150,000,000	7.82
61	Louisiana Local Government Environmental Facilities and Community Development Authority Taxable municipal securities) (7/29/2014)	Louisiana Utilities Restoration Corporation Project/ELL	A-1	$ 91,700,000	3.00
			A-2	$ 152,150,000	8.90
			Total	$ 243,850,000	6.68
60	Louisiana Local Governments Environmental Facilities Authority (Taxable municipal securities) (7/29/2014)	Louisiana Utilities Restoration Corporation Project/EGSL	A-1	$ 71,000,000	6.72
59	Consumers 2014 Securitization Funding, LLC (7/14/2014)	Consumers Energy	A-1	$ 124,500,000	3.00
			A-2	$ 139,000,000	8.00
			A-3	$ 114,500,000	12.26
			Total	$ 378,000,000	7.64
58	Appalachian Consumer Rate Relief Funding LLC (11/6/2013)	Appalachian Power Company	A-1	$ 215,800,000	5.00
			A-2	$ 164,500,000	12.24
			Total	$ 380,300,000	8.13
57	Ohio Phase-In-Recovery Funding, LLC (7/23/2013)	Ohio Power Company	A-1	$ 164,900,000	2.25
			A-2	$ 102,508,000	5.08
			Total	$ 267,408,000	3.33
56	FirstEnergy Ohio PIRB Special Purpose Trust 2013 (Issued as pass-through certificates, backed by bonds issued by CEI, OE and TE) (6/12/2013)	The Cleveland Electric Illuminating Company (CEL), Ohio Edison Company (OE), The Toledo Edison Company (TE)	A-1	$ 111,971,000	1.60
			A-2	$ 70,468,000	5.07
			A-3	$ 262,483,000	13.70
			Total	$ 444,922,000	9.29
55	AEP Texas Central Transition Funding III LLC (3/7/2012)	AEP Texas Central Company	A-1	$ 307,900,000	3.00
			A-2	$ 180,200,000	7.00
			A-3	$ 311,900,000	10.76
			Total	$ 800,000,000	6.93
54	CenterPoint Energy Transition Bond Company IV, LLC (1/11/2012)	CenterPoint Energy Houston Electric, LLC	A-1	$ 606,222,000	3.00
			A-2	$ 407,516,000	7.00
			A-3	$ 681,262,000	10.82
			Total	$ 1,695,000,000	7.10
53	Entergy Louisiana Investment Recovery Funding I, LLC (9/15/2011)	Entergy Louisiana, LLC	A-1	$ 207,156,000	5.27
			Total	$ 207,156,000	5.27
52	Entergy Arkansas Energy Restoration Funding, LLC (8/11/2010)	Entergy Arkansas, Inc.	A-1	$ 124,100,000	5.44
			Total	$ 124,100,000	5.44
51	Louisiana Local Government Environmental Facilities and Community Development Authority (Taxable municipal securities) (7/15/2010)	Louisiana Utilities Restoration Corporation Project/ELL	A-1	$ 112,000,000	2.00
			A-2	$ 111,000,000	5.00
			A-3	$ 121,000,000	8.00
			A-4	$ 124,900,000	10.90
			Total	$ 468,900,000	6.63
50	Louisiana Local Government Environmental Facilities and Community Development Authority (Taxable municipal securities) (7/15/2010)	Louisiana Utilities Restoration Corporation Project/EGSL	A-1	$ 97,000,000	3.00
			A-2	$ 60,000,000	7.00
			A-3	$ 87,100,000	10.40
			Total	$ 244,100,000	6.62
49	MP Environmental Funding LLC (12/16/2009)	Monongahela Power	A-1	$ 64,380,000	19.02
			Total	$ 64,380,000	19.02
48	PE Environmental Funding LLC (12/16/2009)	Potomac Edison	A-1	$ 21,510,000	19.02
			Total	$ 21,510,000	19.02

Deal #	Issuer	Utility Beneficiary	Tranche	Amount	Weighted Average Life (years)
47	CenterPoint Energy Restoration Bond Company, LLC (11/18/2009)	CenterPoint Energy Houston Electric, LLC	A-1	$ 224,788,000	3.00
			A-2	$ 160,152,000	7.00
			A-3	$ 279,919,000	10.82
			Total	$ 664,859,000	7.26
46	Entergy Texas Restoration Funding, LLC (10/29/09)	Entergy Texas, Inc.	A-1	$ 182,500,000	3.00
			A-2	$ 144,800,000	7.00
			A-3	$ 218,600,000	10.86
			Total	$ 545,900,000	7.21
45	Louisiana Public Facilities Authority (Taxable municipal securities) (8/20/2008)	Louisiana Utilities Restoration Corporation/EGSL	A-1	$ 103,000,000	2.66
			A-2	$ 90,000,000	6.24
			A-3	$ 85,400,000	8.97
			Total	$ 278,400,000	5.75
44	Louisiana Public Facilities Authority (Taxable municipal securities) (7/22/2008)	Louisiana Utilities Restoration Corporation/ELL	A-1	$ 160,000,000	1.99
			A-2	$ 367,000,000	5.97
			A-3	$ 160,700,000	9.32
			Total	$ 687,700,000	5.83
43	Cleco Katrina/Rita Hurricane Recovery Funding LLC (2/28/2008)	Cleco Power LLC	A-1	$ 113,000,000	5.00
			A-2	$ 67,600,000	10.58
			Total	$ 180,600,000	7.09
42	CenterPoint Energy Transition Bond III, LLC (1/29/2008)	CenterPoint Energy Houston Electric, LLC	A-1	$ 301,427,000	5.00
			A-2	$ 187,045,000	10.52
			Total	$ 488,472,000	7.11
41	Entergy Gulf States Reconstruction Funding I, LLC (6/22/2007)	Entergy Gulf States, Inc.	A-1	$ 93,500,000	2.99
			A-2	$ 121,600,000	7.99
			A-3	$ 114,400,000	12.24
			Total	$ 329,500,000	8.05
40	RSB BondCo LLC (6/22/2007)	Baltimore Gas & Electric	A-1	$ 284,000,000	2.99
			A-2	$ 220,000,000	6.99
			A-3	$ 119,200,000	9.27
			Total	$ 623,200,000	5.60
39	FPL Recovery Funding LLC (5/15/07)	Florida Power & Light	A-1	$ 124,000,000	1.97
			A-2	$ 140,000,000	4.98
			A-3	$ 100,000,000	7.31
			A-4	$ 288,000,000	10.38
			Total	$ 652,000,000	7.15
38	MP Environmental Funding LLC (4/3/2007)	Monongahela Power	A-1	$ 86,200,000	4.00
			A-2	$ 76,000,000	10.00
			A-3	$ 153,250,000	16.00
			A-4	$ 29,025,000	20.00
			Total	$ 344,475,000	12.01
37	PE Environmental Funding LLC (4/3/2007)	Potomac Edison	A-1	$ 28,450,000	4.00
			A-2	$ 25,700,000	10.00
			A-3	$ 50,700,000	16.10
			A-4	$ 9,975,000	19.94
			Total	$ 114,825,000	12.07
36	AEP Texas Central Transition Funding II LLC (10/4/2006)	AEP Texas Central Company	A-1	$ 217,000,000	2.00
			A-2	$ 341,000,000	5.00
			A-3	$ 250,000,000	7.58
			A-4	$ 437,000,000	10.00
			A-5	$ 494,700,000	12.68
			Total	$ 1,739,700,000	8.44
35	JCP&L Transition Funding II LLC (8/4/2006)	Jersey Central Power & Light	A-1	$ 56,348,000	3.00
			A-2	$ 25,693,000	7.00
			A-3	$ 49,220,000	10.00
			A-4	$ 51,139,000	13.40
			Total	$ 182,400,000	8.37

Deal #	Issuer	Utility Beneficiary	Tranche	Amount	Weighted Average Life (years)
34	CenterPoint Energy Transition Bond Company II, LLC	CenterPoint Houston	A-1	$ 250,000,000	2.02
	(12/9/2005)		A-2	$ 368,000,000	5.00
			A-3	$ 252,000,000	7.47
			A-4	$ 519,000,000	10.01
			A-5	$ 462,000,000	12.71
			Total	$ 1,851,000,000	8.26
33	PG&E Energy Recovery Funding LLC	Pacific Gas & Electric	A-1	$ 351,000,000	2.00
	(11/3/2005)		A-2	$ 372,000,000	5.00
			A-3	$ 121,461,000	6.83
			Total	$ 844,461,000	4.02
32	WPP Funding LLC	West Penn Power	A-1	$ 115,000,000	4.24
	(9/22/2005)		Total	$ 115,000,000	4.24
31	PSE&G Transition Funding II LLC	Public Service Electric & Gas	A-1	$ 25,200,000	2.00
	(9/9/2005)		A-2	$ 35,000,000	5.00
			A-3	$ 20,000,000	7.47
			A-4	$ 22,500,000	9.16
			Total	$ 102,700,000	5.66
30	Massachusetts RRB Special Purpose Trust 2005-1	Boston Edison and Commonwealth Electric	A-1	$ 109,200,000	1.00
	(BEC Funding ll, LLC $265.5M and CEC Funding, LLC $409.0M)		A-2	$ 154,000,000	2.50
	2/15/2005		A-3	$ 266,500,000	5.00
			A-4	$ 144,800,000	7.40
			Total	$ 674,500,000	4.30
29	PG&E Energy Recovery Funding LLC	Pacific Gas & Electric	A-1	$ 268,000,000	1.00
	(2/3/2005)		A-2	$ 647,000,000	3.00
			A-3	$ 320,000,000	5.00
			A-4	$ 468,000,000	6.50
			A-5	$ 184,864,000	7.68
			Total	$ 1,887,864,000	4.38
28	Rockland Electric Company Transition Funding LLC	Rockland Electric	A-1	$ 46,300,000	8.70
	(7/28/04)		Total	$ 46,300,000	8.70
27	TXU Electric Delivery Transition Bond Company LLC	Oncor Electric Delivery Company	A-1	$ 279,000,000	3.00
	(5/28/2004)		A-2	$ 221,000,000	7.00
			A-3	$ 289,777,000	10.43
			Total	$ 789,777,000	6.85
26	Atlantic City Electric Transition Funding LLC	Atlantic City Electric	A-1	$ 46,000,000	2.97
	(12/18/2003)		A-2	$ 52,000,000	8.24
			A-3	$ 54,000,000	12.90
			Total	$ 152,000,000	8.30
25	Oncor Electric Delivery Transition Bond Company LLC	Oncor Electric Delivery Company	A-1	$ 103,000,000	2.00
	(8/14/2003)		A-2	$ 122,000,000	5.00
			A-3	$ 130,000,000	8.00
			A-4	$ 145,000,000	10.83
			Total	$ 500,000,000	6.85
24	Atlantic City Electric Transition Funding LLC	Atlantic City Electric	A-1	$ 109,000,000	3.00
	(12/11/2002)		A-2	$ 66,000,000	7.00
			A-3	$ 118,000,000	10.50
			A-4	$ 147,000,000	15.39
			Total	$ 440,000,000	9.75
23	JCP&L Transition Funding LLC	Jersey Central Power & Light	A-1	$ 91,111,000	3.00
	(6/4/2002)		A-2	$ 52,297,000	7.00
			A-3	$ 77,075,000	10.00
			A-4	$ 99,517,000	13.40
			Total	$ 320,000,000	8.57
22	CPL Transition Funding LLC	Central Power & Light	A-1	$ 128,950,233	1.90
	(1/31/2002)		A-2	$ 154,506,810	4.70
			A-3	$ 107,094,258	7.20
			A-4	$ 214,926,738	10.00
			A-5	$ 191,856,858	13.00
			Total	$ 797,334,897	8.01

Deal #	Issuer	Utility Beneficiary	Tranche	Amount	Weighted Average Life (years)
21	PSNH Funding LLC 2	Public Service Company of New Hampshire	A-1	$ 50,000,000	3.50
	(1/16/2002)		Total	$ 50,000,000	3.50
20	Consumers Funding LLC	Consumers Energy	A-1	$ 26,000,000	1.00
	(10/31/2001)		A-2	$ 84,000,000	3.00
			A-3	$ 31,000,000	5.00
			A-4	$ 95,000,000	7.00
			A-5	$ 117,000,000	10.00
			A-6	$ 115,592,000	12.80
			Total	$ 468,592,000	8.00
19	Reliant Energy Transition Bond Company I, LLC	Reliant Energy	A-1	$ 115,000,000	2.71
	(10/17/2001)		A-2	$ 118,000,000	5.19
			A-3	$ 130,000,000	7.19
			A-4	$ 385,987,000	10.29
			Total	$ 748,987,000	7.78
18	Massachusetts RRB Special Purpose Trust WMECO-1	Western Massachusetts Electric	A-1	$ 155,000,000	7.00
	(5/14/2001)		Total	$ 155,000,000	7.00
17	PSNH Funding LLC	Public Service Company of New Hampshire	A-1	$ 75,211,483	1.09
	(4/20/2001)		A-2	$ 214,649,395	5.04
			A-3	$ 235,139,122	9.99
			Total	$ 525,000,000	6.69
16	Connecticut RRB Special Purpose Trust CL&P-1	Connecticut Light and Power	A-1	$ 224,858,822	1.18
	(3/27/2001)		A-2	$ 255,056,333	3.16
			A-3	$ 292,381,624	5.16
			A-4	$ 287,907,878	7.02
			A-5	$ 378,195,343	8.89
			Total	$ 1,438,400,000	5.54
15	The Detroit Edison Securitization Funding LLC	Detroit Edison Company	A-1	$ 124,540,305	1.50
	(3/2/2001)		A-2	$ 179,037,815	3.30
			A-3	$ 322,791,421	5.80
			A-4	$ 406,722,416	8.80
			A-5	$ 326,236,780	11.30
			A-6	$ 390,671,263	13.30
			Total	$ 1,750,000,000	8.64
14	PECO Energy Transition Trust	PECO Energy	A-1	$ 805,500,000	9.25
	(2/15/2001)		Total	$ 805,500,000	9.25
13	PSE&G Transition Funding LLC	Public Service Electric & Gas	A-1	$ 105,249,914	1.00
	(1/25/2001)		A-2	$ 368,980,380	2.90
			A-3	$ 182,621,909	4.88
			A-4	$ 496,606,425	7.02
			A-5	$ 328,032,965	9.38
			A-6	$ 453,559,632	11.39
			A-7	$ 219,688,870	12.99
			A-8	$ 370,259,905	14.27
			Total	$ 2,525,000,000	8.69
12	PECO Energy Transition Trust	PECO Energy	A-1	$ 110,000,000	1.11
	(4/27/2000)		A-2	$ 140,000,000	2.08
			A-3	$ 398,900,000	8.74
			A-4	$ 351,100,000	9.33
			Total	$ 1,000,000,000	7.18
11	West Penn Funding, LLC	West Penn Power	A-1	$ 74,000,000	1.00
	(11/3/1999)		A-2	$ 172,000,000	3.00
			A-3	$ 198,000,000	5.50
			A-4	$ 156,000,000	7.80
			Total	$ 600,000,000	4.83
10	PP&L Transition Bond Company LLC	Pennsylvania Power & Light	A-1	$ 293,000,000	1.00
	(7/29/1999)		A-2	$ 178,000,000	2.00
			A-3	$ 303,000,000	3.00
			A-4	$ 201,000,000	4.00
			A-5	$ 313,000,000	5.00
			A-6	$ 223,000,000	6.00
			A-7	$ 455,000,000	7.22
			A-8	$ 454,000,000	8.75
			Total	$ 2,420,000,000	5.17

Deal #	Issuer	Utility Beneficiary	Tranche	Amount	Weighted Average Life (years)
9	Massachusetts RRB Special Purpose Trust BEC-1 (7/27/1999)	Boston Edison	A-1	$ 108,500,000	1.09
			A-2	$ 170,600,000	3.13
			A-3	$ 103,400,000	5.13
			A-4	$ 170,900,000	7.13
			A-5	$ 171,600,000	9.63
			Total	$ 725,000,000	5.59
8	Sierra Pacific (4/8/1999)	Sierra Pacific Power	A-1	$ 24,000,000	
			Total	$ 24,000,000	
7	PECO Energy Transition Trust (3/18/1999)	PECO Energy	A-1	$ 244,500,000	1.30
			A-2	$ 275,400,000	3.27
			A-3	$ 667,000,000	4.04
			A-4	$ 458,500,000	5.38
			A-5	$ 464,600,000	6.29
			A-6	$ 993,400,000	7.28
			A-7	$ 896,700,000	8.92
			Total	$ 4,000,100,000	6.13
6	MPC Natural Gas Funding Trust 1998-1 (12/22/1998)	Montana Power	A-1	$ 64,000,000	
			Total	$ 64,000,000	
5	Illinois Power Special Purpose Trust (12/10/1998)	Illinois Power	A-1	$ 110,000,000	0.79
			A-2	$ 100,000,000	1.79
			A-3	$ 80,000,000	2.93
			A-4	$ 85,000,000	3.93
			A-5	$ 175,000,000	5.17
			A-6	$ 175,000,000	7.40
			A-7	$ 139,000,000	9.54
			Total	$ 864,000,000	5.05
4	ComEd Transitional Funding Trust (12/7/1998)	Commonwealth Edison	A-1	$ 426,600,000	0.88
			A-2	$ 423,400,000	2.04
			A-3	$ 259,300,000	3.04
			A-4	$ 420,700,000	4.04
			A-5	$ 598,700,000	5.54
			A-6	$ 761,300,000	7.54
			A-7	$ 510,000,000	9.41
			Total	$ 3,400,000,000	5.17
3	California Infrastructure and Economic Development Bank Special Purpose Trust SDG&E,-1 (12/4/1997)	San Diego Gas & Electric	A-1	$ 65,800,000	0.77
			A-2	$ 82,600,000	1.78
			A-3	$ 66,200,000	2.92
			A-4	$ 65,700,000	3.92
			A-5	$ 96,500,000	5.15
			A-6	$ 197,600,000	7.29
			A-7	$ 83,500,000	9.52
			Total	$ 657,900,000	5.14
2	California Infrastructure and Economic Development Bank Special Purpose Trust SCE-1 (12/4/1997)	Southern California Edison	A-1	$ 246,000,000	0.79
			A-2	$ 307,000,000	1.79
			A-3	$ 248,000,000	2.93
			A-4	$ 246,000,000	3.93
			A-5	$ 361,000,000	5.17
			A-6	$ 740,000,000	7.40
			A-7	$ 315,000,000	9.54
			Total	$ 2,463,000,000	5.19
1	PG&E Funding LLC (11/25/1997)	Pacific Gas & Electric	A-1	$ 125,000,000	0.56
			A-2	$ 265,000,000	1.09
			A-3	$ 280,000,000	1.99
			A-4	$ 300,000,000	3.01
			A-5	$ 290,000,000	4.02
			A-6	$ 375,000,000	5.17
			A-7	$ 866,000,000	7.31
			A-8	$ 400,000,000	9.48
			Total	$ 2,901,000,000	5.19
	Total of all taxable utility securitizations on behalf of IOU ratepayers			$ 49,892,092,897	

* Excludes two transactions for the benefit of ratepayers of the Long Island Power Authority (a governmental utility) in 2013 and 2015, which were a combination of taxable and tax-exempt debt.

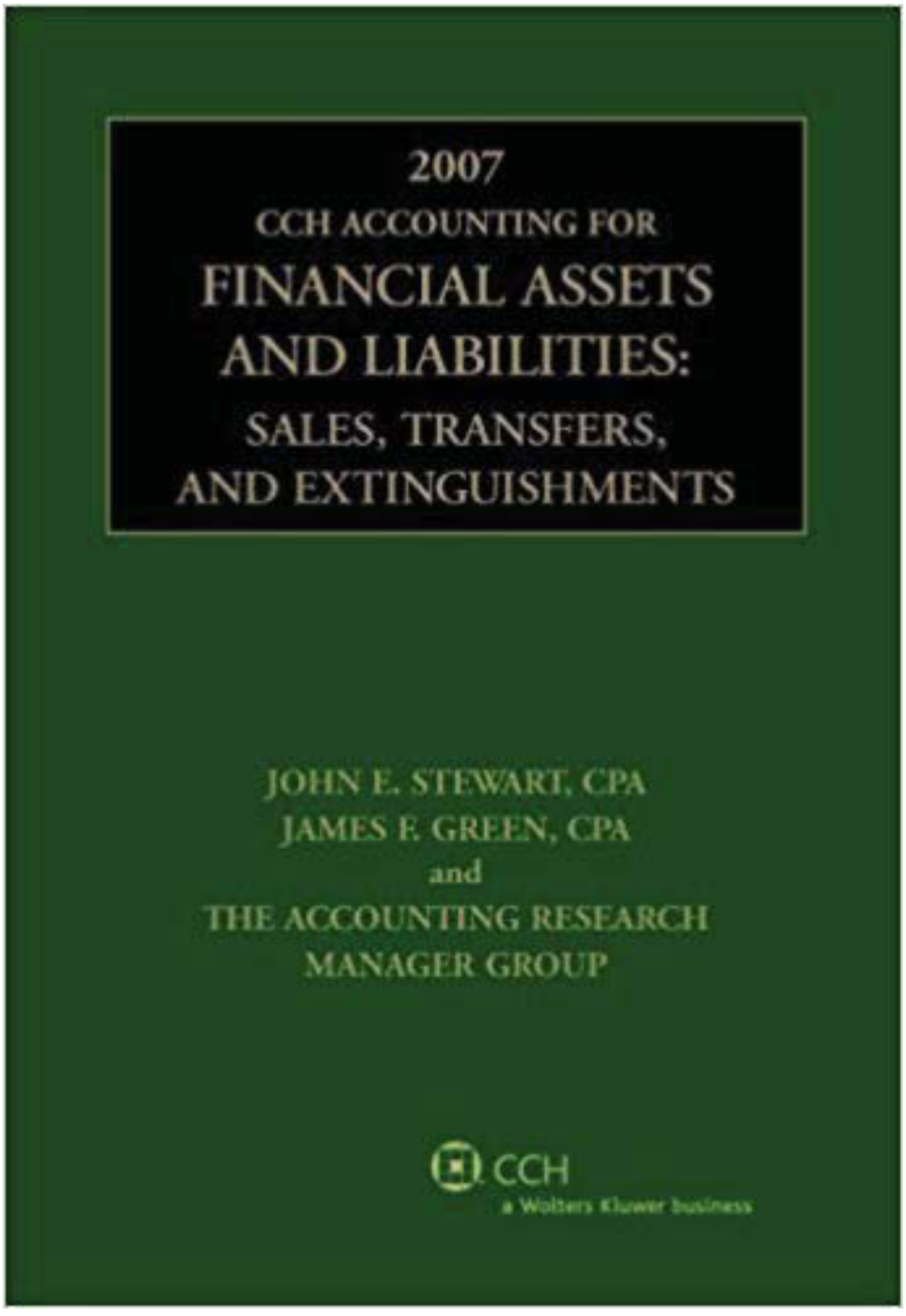
Exhibit D

Moody's		S&P		Fitch		Rating description	
Long-term	Short-term	Long-term	Short-term	Long-term	Short-term		
Aaa	P-1	AAA	A-1+	AAA	F1+	Prime	Investment-grade
Aa1		AA+		AA+		High grade	
Aa2		AA		AA			
Aa3		AA−		AA−			
A1		A+	A-1	A+	F1	Upper medium grade	
A2		A		A			
A3	P-2	A−	A-2	A−	F2		
Baa1		BBB+		BBB+		Lower medium grade	
Baa2	P-3	BBB	A-3	BBB	F3		
Baa3		BBB−		BBB−			
Ba1	Not prime	BB+	B	BB+	B	Non-investment grade speculative	Non-investment grade AKA high-yield bonds AKA junk bonds
Ba2		BB		BB			
Ba3		BB−		BB−			
B1		B+		B+		Highly speculative	
B2		B		B			
B3		B−		B−			
Caa1		CCC+	C	CCC	C	Substantial risks	
Caa2		CCC				Extremely speculative	
Caa3		CCC−				Default imminent with little prospect for recovery	
Ca		CC					
		C					
C		D	/	DDD	/	In default	
/				DD			
				D			

Exhibit E

Purpose	State(s)
Unrecovered costs of nuclear plant retired early	Florida
Buydown of high-cost PPAs	New Hampshire
Deferred balances (regulatory assets)	New Jersey Maryland Ohio West Virginia
Stranded costs in connection with electric industry deregulation	Pennsylvania Texas New Hampshire Illinois Montana Massachusetts New Jersey Michigan Connecticut Louisiana
Storm recovery costs	Florida Louisiana Texas Arkansas
Costs of new pollution control equipment at existing electric generating facilities	West Virginia Wisconsin
Costs of new renewable distributed generation	Hawaii

Exhibit E.i


2007
CCH ACCOUNTING FOR
FINANCIAL ASSETS AND LIABILITIES:
SALES, TRANSFERS, AND EXTINGUISHMENTS
JOHN E. STEWART, CPA
JAMES F. GREEN, CPA
and
THE ACCOUNTING RESEARCH MANAGER GROUP
CCH
a Wolters Kluwer business

Question: Is a transfer of trade receivables for which the related goods or services have been provided, but for which the related receivables have not been billed, a transfer of financial assets that is accounted for under Statement 140?

Response: Yes. A common situation that creates unbilled receivables is when a utility company is able to recognize revenue for the service it provides to its customers but, due to its billing cycle, the customers are not invoiced until a later date. Since the utility has provided the service to its customer, it has a contractual right to receive payment for services rendered and generally would have recognized the related sale of electricity as revenue. Thus, unbilled receivables are recorded financial assets, the transfer of which would be accounted for under Statement 140. One possible technique to determine whether the would-be transferor has a contractual right to receive payment equal to the amount of the unbilled receivable would be to confirm the existence of the receivable amount with a sample of customers.

4-12. Securitization of Regulatory Assets

Summary: Regulatory assets (often called stranded costs) are not financial assets and therefore are not covered by Statement 140. The SEC staff believes EITF Issue No. 88-18, "Sales of Future Revenues," covers them.

Question (from FASB Staff Implementation Guide, Question 6):

> The deregulation of utility rates charged for electric power generation has caused electricity-producing companies to identify some of their electric power generation operations as "stranded costs." Prior to deregulation, utilities typically expected to be reimbursed for costs through regulation of rates charged to customers. After deregulation, some of these costs may no longer be recoverable through unregulated rates. Hence, such potentially unrecoverable costs often are referred to as stranded costs. However, some of those stranded costs may be recovered through a surcharge or tariff imposed on rate-regulated goods or services provided by another portion of the entity whose pricing remains regulated.
>
> Some entities have securitized their enforceable rights to impose that tariff (often referred to as "securitized stranded costs"), thereby obtaining cash from investors in exchange for the future cash flows to be realized from collecting surcharges imposed on customers of the rate-regulated goods or services. Are securitized stranded

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costs considered to be financial assets, the transfer of which would be within the scope of Statement 140?

Response (from FASB Staff Implementation Guide, Question 6):

No. Paragraph 364 defines *financial asset* as "...a contract that conveys to a second entity a *contractual right* (a) to receive cash or another financial instrument from a first entity or (b) to exchange other financial instruments on potentially favorable terms with the first entity" (emphasis added). Therefore, to be a financial asset, an asset must arise from a contractual agreement between two or more parties, not by an imposition of an obligation by one party on another. This notion in Statement 140 is consistent with the notion discussed in paragraph 39 of FASB Statement No. 105, *Disclosure of Information about Financial Instruments with Off-Balance-Sheet Risk and Financial Instruments with Concentrations of Credit Risk*,[2] which stated:

> Other contingent items that ultimately may require the payment of cash but do not as yet arise from contracts, such as contingent liabilities for tort judgments payable, are not financial instruments. However, when those obligations become enforceable by government or courts of law and are thereby contractually reduced to fixed payment schedules, the items would be financial instruments under the definition.

Securitized stranded costs are not financial assets, and therefore transfers of securitized stranded costs are not within the scope of Statement 140. Securitized stranded costs are not financial assets because they are imposed on ratepayers by a state government or its regulatory commission and, thus, while an enforceable right for the utility, they are not a *contractual* right to receive payments from another party. To elaborate, while a right to collect cash flows exists, *it is not the result of a contract* and, thus, not a financial asset. Refer to Question 7 [Interpretation 2-4].

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[2] Although Statement 105 was superseded by FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities*, the Board's definition of *financial asset* continues to be based on the definition of a financial instrument found in Statement 105.

Commentary: We discussed this issue with the SEC staff before the issuance of the FASB Staff Implementation Guide on Statement 125 (which preceded the Statement 140 FASB Staff Implementation

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Guide). The SEC staff concluded that regulatory assets are not financial assets. The staff believes the legislation that provides for the securitization of regulatory assets simply allows the utility's regulatory authority to impose a tariff on electricity sold in the future. The law, however, does not transform regulatory assets into financial assets since they generally do not qualify to be accounted for as revenue until they are "billable" to the customer. The basis for the SEC staff's conclusion is that the resulting law creates an enforceable right (which is a right imposed on one party by another, such as a property tax), but not a contractual right. The SEC staff, after consulting with the FASB staff, concluded that the FASB specifically limited financial assets to contractual rights to cash or other financial assets, which are essentially a subset of enforceable rights. Thus, such an enforceable right does not meet the definition of a financial asset.

The SEC staff also concluded that the proceeds received by the utility do not represent cash for assets sold, but cash received for future services. This approach effectively precludes accounting for this type of a transaction as a sale outside of Statement 140. The SEC staff believes the proceeds represent debt. EITF Issue No. 88-18, "Sales of Future Revenues," provides the most relevant guidance to make that determination (see Interpretation 4-9).

4-13. Transfers of Minimum Lease Payments Under an Operating Lease

Summary: Transfers of contractual payments receivable under an operating lease are not within the scope of Statement 140.

Question (from FASB Staff Implementation Guide, Question 1):

> If a right to receive the minimum lease payments to be received under an operating lease is transferred, could it be considered a financial asset within the scope of Statement 140?

Response (from FASB Staff Implementation Guide, Question 1):

> No. A right to receive the minimum lease payments to be received under an operating lease is an unrecognized financial asset. As stated in paragraph 4, Statement 140 "does not address... transfers of unrecognized financial assets, for example, minimum lease payments to be received under operating leases."

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TWELFTH EDITION

ACCOUNTANTS' HANDBOOK

VOLUME TWO:
Special Industries and Special Topics

Lynford Graham
D.R. Carmichael

asset's carrying amount and subsequently allocated to expense over that asset's useful life. ASC Topic 410 includes special provisions for entities that apply ASC Topic 980. Differences between amounts collected through rates and amounts recognized in accordance with ASC Topic 410 were recognized as regulatory assets and liabilities if the requirements of ASC Topic 980 were met.

(v) Securitization of Stranded Costs, Including Regulatory Assets. In connection with the electric industry restructuring efforts that occurred in a number of states, regulatory mechanisms were established to mitigate potential stranded costs. The legislative or regulatory framework for moving to a competitive marketplace included provisions when issued for the affected companies to securitize or "monetize" all or a portion of their stranded costs through the issuance of debt securities that would provide the utility with a lower cost of capital than that to which they were previously exposed. Generally, such provisions establish a separate unbundled revenue stream from the current bundled stream, surcharge, or tariff that would be the source of recovery from a company's rate payers for the stranded costs. Companies securitize their rights to impose such revenue stream, surcharge, or tariff by receiving cash flows from investors in exchange for future cash flows to be collected from customers. The utility would issue debt obligations in an amount equal to its stranded costs (or portion thereof). The resulting debt obligations would be nonrecourse since the company would sell the stranded costs to a credit-enhanced, bankruptcy remote special-purpose entity or trust established to finance the purchase through the sale of state-authorized debt. Collections of the tariff by the company would be passed through to holders of the debt as periodic payments of interest and principal.

The potential benefits to a company from securitizing stranded costs include the opportunity to improve credit quality and to use the proceeds to reduce leverage and fixed charges, or fund the termination of uneconomic contracts. The expectation is that monetizing the stranded costs would result in lower rates for consumers since higher cost of capital is effectively replaced by traditional utility debt with lower cost.

In February 1997, the SEC's Office of Chief Accountant provided financial reporting guidance to California's utility registrants for proceeds received in connection with a stranded cost securitization. The SEC Staff concluded that the proceeds received should be classified as either debt or deferred revenue based on the guidance in ASC Topic 470-10-25, *Debt*.

ASC Topic 470-10-25 reached a consensus that the presence of any one of six specifically identified factors independently creates a rebuttable presumption that classification of the proceeds as debt is appropriate. The facts and circumstances of stranded cost securitization transactions will typically result in the presence of one or more of the factors. Thus, securitization proceeds are generally expected to be classified as debt for financial reporting purposes.

ASC Topic 470-10-25 also concluded that amounts recorded as debt should be amortized under the interest method. Generally, this will result in an increasing amount of stranded cost recognition in the income statement during the securitization period. This occurs because the amount recognized will equal the principal portion (on a mortgage basis) of the tariffed debt service cost that is billable to customers and recorded as revenue during each period.

In connection with providing classification guidance, the SEC Staff also concluded that regulatory assets are not financial assets. This is supported by ASC Topic 860-55-8, *Transfers and Servicing*, and SFAS No. 166, *Accounting for Transfers of Financial Assets—an Amendment of FASB No. 140*-FASB Statement Appendix C paragraph 6. Further, the legislation that provides for the securitization of regulatory assets simply allows the utility's regulator to impose a surcharge or tariff on electricity sold in the future. The law, however, does not transpose regulatory assets into financial assets. The basis for the SEC Staff's conclusion is that the resulting law creates an enforceable right (which is a right imposed on one party by another, such as a property tax) and not a contractual right. The SEC Staff, after consulting with the FASB Staff, concluded that the FASB specifically limited financial assets to a contractual right, which is essentially a subset of an enforceable right. Thus, enforceable rights that are not contractual rights do not meet the definition of a financial asset under ASC Topic 860-55-8. However, beneficial interests in a securitization trust that holds nonfinancial assets, such as securitized stranded costs, would be considered financial

Financial Accounting Standards Board (FASB)
Accounting Standards Codification (ASC)
Topic 860-10-55-8

Securitized stranded costs are not financial assets, and therefore transfers of securitized stranded costs are not within the scope of this Subtopic. Securitized stranded costs are not financial assets because they are imposed on ratepayers by a state government or its regulatory commission and, thus, while an enforceable right for the utility, they are not a contractual right to receive payments from another party. To elaborate, while a right to collect cash flows exists, it is not the result of a contract and, thus, not a financial asset.

Exhibit E.iv

Regulation AB
Item 1101

September 19, 2007

Response of the Office of Chief Counsel
Division of Corporation Finance

Re: MP Environmental Funding LLC, PE Environmental Funding LLC
Incoming letter dated September 7, 2007

Capitalized terms used in this response have the same meaning as defined in your letter. Based on the facts presented, it is the Division's view that MP Funding and PE Funding are not asset-backed issuers and the Bonds are not asset-backed securities within the meaning of Item 1101 of Regulation AB. Notwithstanding that conclusion, the Division will not recommend enforcement action to the Commission if the Issuers file periodic reports related to the Bonds in compliance with the disclosure and reporting regime established in Regulation AB.

This position is based on the representations made to the Division in your letter. Any different facts or conditions might require the Division to reach a different conclusion. Moreover, with the exception of the position concerning the status of the Issuers and Bonds under Item 1101 of Regulation AB, this response merely expresses the Division's position on enforcement action, and does not purport to express any legal conclusions on the questions presented.

Sincerely,

Jeffrey S. Cohan
Special Counsel

From SEC website https://www.sec.gov/divisions/corpfin/cf-noaction/2007/mpef091907-1101.htm.

Filed Pursuant to Rule 424(b)(1)
File No. 333-209196 and 333-209196-01

Exhibit F.i

PROSPECTUS

$1,294,290,000 SERIES A SENIOR SECURED BONDS,

DUKE ENERGY FLORIDA, LLC

Sponsor, Depositor and Initial Servicer
Central Index Key Number: 0000037637

DUKE ENERGY FLORIDA PROJECT FINANCE, LLC

Issuing Entity
Central Index Key Number: 0001669374

Series A Bonds	Expected Weighted Average Life (Years)	Principal Amount Offered	Scheduled Final Payment Date	Final Maturity Date	Interest Rate	Initial Price to Public	Underwriting Discounts and Commissions	Proceeds to Issuer (Before Expenses)
Series A 2018	2.0	$ 183,000,000	03/01/2020	03/01/2022	1.196%	99.999%	0.25%	$ 182,540,670
Series A 2021	5.0	$ 150,000,000	09/01/2022	09/01/2024	1.731%	99.998%	0.40%	$ 149,397,000
Series A 2026	10.0	$ 436,000,000	09/01/2029	09/01/2031	2.538%	99.996%	0.50%	$ 433,802,560
Series A 2032	15.2	$ 250,000,000	03/01/2033	03/01/2035	2.858%	99.995%	0.65%	$ 248,362,500
Series A 2035	18.7	$ 275,290,000	09/01/2036	09/01/2038	3.112%	99.994%	0.70%	$ 273,346,453

The total price to the public is $1,294,238,713. The total amount of the underwriting discounts and commissions is $6,789,530. The total amount of proceeds to Duke Energy Florida Project Finance, LLC before deduction of expenses (estimated to be $9,163,470) is $1,287,449,183.

Duke Energy Florida, LLC, as **depositor**, is offering $1,294,290,000 aggregate principal amount of Series A Senior Secured Bonds listed above (each weighted average life designation a "WAL" and the five WALs collectively, the **Series A Bonds** or the **bonds)**, to be issued by Duke Energy Florida Project Finance, LLC, referred to herein as **DEF Project Finance**, as **issuing entity**.

The Series A Bonds are senior secured obligations of DEF Project Finance, and are its obligations only. The Series A Bonds are supported by **nuclear asset-recovery property**, which consists of all rights and interest of DEF Project Finance under the financing order, including the right to impose, bill, collect and receive irrevocable, binding, nonbypassable charges based on the usage of electricity. These charges pay principal, interest and expenses of the Series A Bonds and are known as **nuclear asset-recovery charges,** or as **ratepayer obligation charges** or **ROCs** and upon the issuance of the bonds may not be reduced, impaired, postponed, terminated or otherwise adjusted by the Florida Commission except as adjusted pursuant to the true-up mechanism described herein. These charges will be paid on a joint and several basis by all existing or future customers (individuals, corporations, other business entities, the State of Florida and other federal, state and local government entities) receiving transmission or distribution service from Duke Energy Florida, LLC, or **DEF**, or its successors or assignees under rate schedules approved by the Florida Commission or under special contracts. Nuclear asset-recovery charges are payable by customers even if the customers elect to purchase electricity from an alternative electricity supplier following a fundamental change in regulation of public utilities in Florida. Nuclear asset-recovery property includes the right to a mandatory true-up mechanism for making any adjustments that are necessary to correct for any overcollection or undercollection of nuclear asset-recovery charges or to otherwise ensure the timely payment of principal of and interest on the bonds when due and other financing costs and other required amounts and charges payable in connection with the bonds. With respect to the foregoing, interest is due on each payment date and principal is due upon the final maturity date for each WAL.

The Series A Bonds do not constitute a debt, liability or other obligation of, or interest in, DEF or any of its other affiliates (other than us). The bonds will not be insured or guaranteed by DEF, including in its capacity as sponsor, depositor, seller or servicer, or by its parent, Duke Energy Corporation, any of their respective affiliates, the indenture trustee or any other person or entity. The Series A Bonds will be nonrecourse obligations, secured only by the collateral. The Series A Bonds are not a debt or general obligation of the Florida Commission, the State of Florida or any of its political subdivisions, agencies, or instrumentalities. However, in so far as the State of Florida or any such political subdivision, agency or instrumentality is receiving transmission or distribution service from DEF or its successor or assignee, such governmental entity will be obligated, in its capacity as a customer, to pay nuclear asset-recovery charges.

The Series A Bonds are a type of ratepayer obligation charge or **ROC bonds**, to be issued pursuant to a special Florida statute, or the **Financing Act**, and an irrevocable **financing order** of the Florida Public Service Commission, or the **FPSC** or the **Florida Commission**. Under the irrevocable financing order, the Florida Commission guarantees it will act, as directed by the Financing Act, to implement the true-up mechanism for making any adjustments that are necessary to correct for any overcollection or undercollection of nuclear asset-recovery charges or to otherwise ensure the timely payment of principal of and interest on the bonds when due and other financing costs and other required amounts and charges payable in connection with the bonds. The Florida Commission's obligations under the Financing Act and the financing order are direct, explicit, irrevocable and unconditional upon issuance of the bonds. Those obligations are legally enforceable against the Florida Commission, a United States public sector entity.

All matters relating to the structuring, marketing and pricing of the Series A Bonds have been considered jointly by DEF, by designated personnel of the Florida Commission and by the Florida Commission's financial advisor. The financial advisor to the Florida Commission is:

Saber Partners, LLC

The bonds will accrue interest from the date of issuance. The bonds are scheduled to pay principal and interest semi-annually and sequentially as described herein. We will pay interest and principal on the bonds on March 1 and September 1 of each year, beginning on March 1, 2017. The Series A Bonds are not subject to optional redemption prior to maturity.

3. The Series A Bonds will be payable only from revenues received by us under the indenture for the bonds and funds on deposit in trust accounts relating to the bonds. These amounts, together with the nuclear asset-recovery property, including the Florida Commission guaranteed true-up mechanism, are the source of funds for the payment of principal of and interest on the Series A Bonds. A capital subaccount will hold the depositor's capital contribution to us. An excess funds subaccount will hold revenues that are collected but not needed to meet current obligations associated with the Series A Bonds. Credit enhancement for the bonds will be provided by the true-up mechanism, as well as the capital subaccount. The primary purpose of the excess funds subaccount is not to provide credit enhancement for the bonds. However, amounts in the excess funds subaccount may be used to make debt service payments on the bonds when needed.

DEF is the depositor, sponsor, seller and initial servicer with regard to the bonds. DEF is the sole member and owner of our equity interest. Our Central Index Key number is 0001669374. DEF's Central Index Key number is 0000037637.

Investing in the Series A Bonds involves risks. See "Risk Factors" beginning on page 21 to read about factors you should consider before buying the Series A Bonds.

NEITHER THE SECURITIES AND EXCHANGE COMMISSION NOR ANY STATE SECURITIES COMMISSION HAS APPROVED OR DISAPPROVED OF THESE SECURITIES OR PASSED UPON THE ACCURACY OR ADEQUACY OF THIS PROSPECTUS. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

The Series A Bonds will be ready for delivery in book-entry form through the facilities of The Depository Trust Company against payment in New York, New York on or about June 22, 2016.

RBC Capital Markets — **GUGGENHEIM SECURITIES**

Joint Book-Running Managers

Drexel Hamilton Ramirez & Co., Inc. — **Jefferies SMBC Nikko** — **MUFG The Williams Capital Group, L.P.**

Senior Co-Managers

The date of this prospectus is June 15, 2016

PROSPECTUS SUMMARY

This summary highlights some information from this prospectus. Because this is a summary, it does not contain all of the information that may be important to you. You should read this prospectus in its entirety before you buy the bonds.

You should carefully consider the Risk Factors beginning on page 21 of this prospectus before you invest in the bonds

Securities offered:	Series A Senior Secured Bonds of Duke Energy Florida Project Finance, LLC, as listed on the cover page of this prospectus (collectively, the "Series A Bonds"), scheduled to pay interest semi-annually and principal semi-annually and sequentially in accordance with the sinking fund schedule described in this prospectus.
Issuing entity (a corporate issuer):	Duke Energy Florida Project Finance, LLC is a special purpose project finance subsidiary of DEF, organized as a Delaware limited liability company. DEF is our sole member and owns all of our equity interests. We are not a municipal issuer. We are not an asset-backed issuer, and the Series A Bonds are not asset-backed securities within the meaning of Item 1101(c) of Regulation AB. We were formed for the limited purpose of purchasing, owning and administering nuclear asset-recovery property, issuing nuclear asset-recovery bonds from time to time (including the Series A Bonds) and performing activities incidental thereto to finance certain activities of DEF related to the retirement of the Crystal River 3 nuclear plant. These are the first nuclear asset-recovery bonds which DEF Project Finance has issued. We may issue additional nuclear asset-recovery bonds, but only as authorized under the financing order or under a new and separate financing order. We are responsible to the State of Florida and the Florida Commission on an ongoing basis as provided in its organizational documents, the transaction documents and the financing order. Please read "The Issuing Entity" in this prospectus. Our address and phone number are as follows: 299 First Avenue North, St. Petersburg, Florida 33701, 704-382-3853.
Corporate financial reporting:	As required by the Financial Accounting Standards Board and the SEC Office of Chief Accountant governing corporate financial reporting for investor-owned utilities, nuclear asset-recovery charges will be reported as revenue on the consolidated income statement of our parent, DEF, a regulated public utility as future electricity transmission and distribution services are billable to customers.
Corporate tax treatment:	The bonds will be treated as debt of DEF for U.S. federal income tax purposes. See "Material U.S. Federal Income Tax Consequences" in this prospectus. For federal income tax purposes, DEF will not recognize gross income unless and until DEF bills customers for the nuclear asset-recovery charges and only in connection with such billing of customers for such nuclear asset-recovery charges.

The depositor, sponsor, seller and initial servicer of the bonds:	DEF is a regulated public utility primarily engaged in the generation, transmission, distribution, and sale of electricity in portions of Florida, including the greater Gainesville, Orlando, St. Petersburg, and Tallahassee areas. DEF's service area covers approximately 13,000 square miles and supplies electric service to approximately 1.7 million residential, commercial and industrial customers. During the twelve months ended December 31, 2015, DEF billed approximately 38.6 billion kilowatt hours of electricity to its covered electric customers in Florida, resulting in revenues of approximately $4.4 billion. The address and phone number of DEF are as follows: 299 First Avenue North, St. Petersburg, Florida 33701. DEF's telephone number is 704-382-3853. DEF is an indirect, wholly owned subsidiary of Duke Energy Corporation. DEF, as initial servicer, will bill and collect nuclear asset-recovery charges and will remit nuclear asset-recovery charge collections daily to the indenture trustee according to the terms of the servicing agreement. Neither DEF nor Duke Energy Corporation nor any other affiliate (other than us) is an obligor of the bonds. The bonds will not be insured or guaranteed by DEF, including in its capacity as sponsor, depositor, seller or servicer, or by its parent, Duke Energy Corporation, any of their respective affiliates, the indenture trustee or any other person or entity. There are currently no other retail electric providers operating in DEF's Florida service territory. See "The Servicing Agreement" in this prospectus. DEF, as initial servicer, will be entitled to receive an annual servicing fee in an amount equal to 0.05% of the aggregate initial principal amount of the bonds. This servicing fee will be payable in equal installments on each semi-annual payment date, in arrears. The indenture trustee will pay the servicing fee (together with any portion of the servicing fee that remains unpaid from prior payment dates) to the extent of available funds prior to the distribution of any interest on and principal of the bonds. DEF, as administrator, will be entitled to receive an annual administration fee of $50,000. This annual administration fee will be payable annually, in arrears. The indenture trustee will pay the administration fee (together with any portion of the administration fee that remains unpaid from prior payment dates) to the extent of available funds prior to the distribution of any interest on and principal of the bonds.

Our relationship with DEF:	On the issue date for the Series A Bonds, DEF will sell nuclear asset-recovery property to us pursuant to a sale agreement between us and DEF. DEF will service the nuclear asset-recovery property pursuant to a servicing agreement between us and DEF. See "The Sale Agreement" and "The Servicing Agreement" in this prospectus. Neither the bonds nor the property securing the bonds is an obligation of DEF or any of its affiliates, except for us.
Our relationship with the Florida Commission:	We are responsible to the Florida Commission, as provided in its organizational documents, the basic documents and the financing order. Please read "The Issuing Entity" in this prospectus.
Our managers:	The following is a list of our managers as of the date of this prospectus:

Name	Age	Title	Background
Stephen G. De May	53	Manager	Stephen G. De May has been Treasurer and Senior Vice President, Tax of Duke Energy Corporation since February 2016. Mr. De May was Senior Vice President and Treasurer of Duke Energy Corporation from 2012 to 2016 and Senior Vice President, Investor Relations and Treasurer of Duke Energy Corporation from 2009 to 2012.
William E. Currens Jr.	47	Manager	William E. Currens Jr. was appointed as Senior Vice President, Chief Accounting Officer and Controller of Duke Energy Corporation, effective May 2016. Prior to that, Mr. Currens served as Vice President, Investor Relations of Duke Energy Corporation since September 2013 and served as General Manager, Investor Relations of Duke Energy Corporation from April 2008 until September 2013.

Name	Age	Title	Background
Bernard J. Angelo	46	Independent Manager	Bernard J. Angelo joined Global Securitization Service, LLC ("GSS") in April 1997. Mr. Angelo actively assists clients and their legal counsel during the structuring phase of their transactions and assimilates bank sponsored commercial paper programs into the operating matrix at GSS. Mr. Angelo has extensive experience in managing commercial paper and medium term note programs, as well as both the business and legal side of structured finance. Fortune 1000 companies have selected Mr. Angelo to serve as independent director for their SPV subsidiaries established to finance commercial real estate, energy infrastructure and many classes of financial assets. Mr. Angelo serves as an independent director for our affiliates, Duke Energy Florida Project Finance, LLC, Duke Energy Receivables Finance Company, LLC, Duke Energy Florida Receivables LLC and Duke Energy Progress Receivables LLC.
Financial advisor to the Florida Commission:			Saber Partners, LLC
Credit ratings:			The bonds are expected to receive credit ratings from at least two nationally recognized statistical rating organizations. Please read "Ratings" in this prospectus.

Bond structure: Sinking fund bonds: Series A 2018 Bonds, expected weighted average life 2.0 years, Series A 2021 Bonds, expected weighted average life 5.0 years, Series A 2026 Bonds, expected weighted average life 10.0 years, Series A 2032 Bonds, expected weighted average life 15.2 years and Series A 2035, expected weighted average life 18.7 years. The bonds are scheduled to pay principal semi-annually and sequentially. See "Weighted Average Life and Yield Considerations for the Bonds" in this prospectus.

Average life profile: Stable, meaning prepayment is not permitted and the aggregate payments of principal of and interest on the bonds and the timing of such payments are not expected to change materially over the life of the bonds under the stress cases analyzed under the heading "Weighted Average Life and Yield Considerations for the Bonds—Sensitivity Analysis—Weighted Average Life" in this prospectus.

Optional redemption: No optional redemption. Non-callable for the life of the bonds.

Payment dates and interest accrual: Semi-annually, March 1 and September 1. Interest will be calculated on a 30/360 basis. The first scheduled payment date is March 1, 2017.

Interest is due on each payment date for the Series A Bonds, and principal for each weighted average life designation or **WAL** is due upon the final maturity date for that WAL. Failure to pay the entire outstanding principal amount of a WAL by the final maturity date for such WAL will result in an event of default. See "Description of the Series A Bonds—Interest Payments Generally", "—Principal" and "—Events of Default; Rights Upon Event of Default" in this prospectus.

	Scheduled Final Payment Dates	Final Maturity Dates
Series A 2018	03/01/2020	03/01/2022
Series A 2021	09/01/2022	09/01/2024
Series A 2026	09/01/2029	09/01/2031
Series A 2032	03/01/2033	03/01/2035
Series A 2035	09/01/2036	09/01/2038

Indenture trustee: The Bank of New York Mellon Trust Company, National Association will act as indenture trustee under the indenture pursuant to which the bonds will be issued.

Minimum denominations of the bonds: $2,000 and integral multiples of $1,000 in excess thereof, except for one bond, which may be of a smaller denomination.

Use of proceeds:	We will use the proceeds of the offering to (i) purchase the nuclear asset-recovery property relating to the bonds from DEF, owner of the retired Crystal River 3 nuclear power plant project, or CR3, who in turn will use the proceeds it receives from the sale of the nuclear asset-recovery property to pay down a portion of its outstanding short-term debt and/or to make an equity distribution to DEF's parent, Duke Energy Corporation, and (ii) pay upfront bond issuance costs.
Background of transaction and the enabling legislation, the Financing Act:	In 2015, the Florida legislature enacted the **Financing Act**, codified as Section 366.95, Florida Statutes. The Financing Act allows electric utilities to access lower-cost funds through nuclear asset-recovery bonds pursuant to financing orders issued by the Florida Commission. One purpose of the Financing Act is to lower the cost to customers associated with the long-term financing of costs incurred in connection with the early retirement or abandonment of a nuclear generating asset unit where such early retirement or abandonment is deemed reasonable and prudent by the Florida Commission through a final order approving a settlement or other final order issued by the Florida Commission before July 1, 2017, and where pretax costs to be financed exceeded $750 million. The Florida Commission issued an irrevocable financing order to DEF on November 19, 2015. Pursuant to that financing order, DEF established DEF Project Finance to be a bankruptcy-remote special purpose subsidiary to issue the nuclear asset-recovery bonds (including the Series A Bonds). In the financing order, the Florida Commission authorized the imposition and collection of nuclear asset-recovery charges on all DEF transmission and distribution customers. DEF, as initial servicer, will collect nuclear asset-recovery charges on our behalf and will remit the nuclear asset-recovery charges to an indenture trustee as described in the "Servicing Agreement—Remittances to Collection Account". Please read "The Nuclear Asset-Recovery Property and the Financing Act" in this prospectus. The Financing Act permits the Florida Commission to impose irrevocable, binding, nonbypassable nuclear asset-recovery charges on all future and existing customers receiving transmission or distribution service from DEF or its successors or assignees under FPSC-approved rate schedules or under special contracts sufficient to pay principal of and interest on the bonds and other administrative expenses of the offering. The Florida Commission governs the amount and terms for collections of these nuclear asset-recovery charges through one or more financing orders issued to DEF and upon the issuance of the bonds these nuclear asset-recovery charges may not be reduced, impaired, postponed, terminated or otherwise adjusted by the Florida Commission except as adjusted pursuant to the true-up mechanism described herein.

Nuclear asset-recovery charges are nonbypassable by customers:	The nuclear asset-recovery charges are *nonbypassable,* consumption-based charges separate and apart from DEF's base rates; the nuclear asset-recovery charges are to be paid by all existing and future customers receiving transmission or distribution service from DEF or its successors or assignees under FPSC-approved rate schedules or under special contracts. Such customers must pay nuclear asset-recovery charges even if DEF goes out of business and its transmission and distribution services are taken over by another utility or if a customer elects to purchase electricity from an alternative electric supplier following a fundamental change in regulation of public utilities in Florida. No customer receiving transmission or distribution service from DEF can avoid the charge. ROCs may not be avoided by DEF's customers and must be paid by such customers until the bonds are paid in full. The only way to avoid the ROCs is to disconnect from DEF's electric grid. See "DEF's Financing Order—Nuclear Asset-Recovery Charges" in this prospectus.
Small initial nuclear asset-recovery charge as a percentage of customer's total electricity bill:	The initial nuclear asset-recovery charge is expected to represent approximately 2.7% of the total bill, as of April 2016, received by 1,000 kWh residential customer of DEF.
Florida state pledge to protect bondholder rights:	The State of Florida has pledged to the bondholders that it will not: • alter the provisions of the Financing Act that make the nuclear asset-recovery charges imposed by the financing order irrevocable, binding, and nonbypassable charges; • take or permit any action that impairs or would impair the value of nuclear asset-recovery property or revises the nuclear asset-recovery costs for which recovery is authorized; or, • except as authorized under the Financing Act with respect to the true-up mechanism, reduce, alter, or impair nuclear asset-recovery charges that are to be imposed, collected, and remitted for the benefit of the bondholders and other financing parties until any and all principal, interest, premium, financing costs and other fees, expenses, or charges incurred, and any contracts to be performed, in connection with the nuclear asset-recovery bonds have been paid and performed in full.

Nothing in this pledge will preclude limitation or alteration if full compensation is made by law for the full protection of the nuclear asset-recovery charges collected pursuant to a financing order and of the bondholders and any assignee or financing party entering into a contract with the electric utility. Please read "Risk Factors—Risks Associated with Potential Judicial, Legislative or Regulatory Actions—Future Florida Legislative Action Might Attempt to Invalidate the Bonds or the Nuclear Asset-Recovery Property" in this prospectus.

This agreement is referred to as the **state pledge**.

The bonds will not be a debt or general obligation of the Florida Commission, the State of Florida, or any of its political subdivisions, agencies, or instrumentalities, and are not a charge on the full faith and credit or taxing power of the State of Florida or any other governmental agency or instrumentality. However, the State of Florida and other governmental entities, to the extent that they are customers, will be obligated to pay nuclear asset-recovery charges securing the bonds.

Florida Commission mandates statutory true-up adjustments to the nuclear asset-recovery charges:

The Financing Act and the financing order require that we, or DEF, file with the Florida Commission at least semi-annually (and quarterly after the scheduled final payment date for the latest maturing bond) a letter applying the true-up mechanism to be reviewed by the Florida Commission for any mathematical errors to correct for any overcollection or undercollection of the nuclear asset-recovery charges and make any adjustments to ensure the recovery of revenues sufficient to provide for the timely payment of scheduled principal of and interest on the bonds and other required amounts and charges payable in connection with the bonds (such amounts, the **periodic payment requirement**). Under the servicing agreement, the servicer will make adjustments to the nuclear asset-recovery charges at least semi-annually. In addition to the semi-annual true-up adjustment, the servicer is authorized to make interim adjustments at any time for any reason to ensure the timely payment of the periodic payment requirement.

In addition, the servicer will make a non-standard true-up adjustment to be effective simultaneously with a base rate change that includes any change in the rate allocation among customers used to determine the nuclear asset-recovery charges.

These adjustments are sometimes referred to as the Florida Commission guaranteed true-up mechanism or the true-up mechanism. Please read "DEF's Financing Order—FPSC Guaranteed True-Up Mechanism" in this prospectus.

Guarantee of Regulatory Action:	The state pledge and the irrevocability of the financing order, in conjunction with the true-up adjustment, constitute a guarantee of regulatory action for the benefit of bondholders. This performance guarantee is pursuant to the irrevocable financing order as authorized by the Financing Act. Please read "DEF's Financing Order—FPSC Guaranteed True-Up Mechanism" in this prospectus. The financing order provides that the true-up mechanism and all other obligations of the Florida Commission pursuant to its irrevocable financing order are direct, explicit, irrevocable and unconditional upon issuance of the bonds and are legally enforceable against the Florida Commission, a United States public sector entity. See "DEF's Financing Order—FPSC Guaranteed True-Up Mechanism—FPSC-Guaranteed True-Up Mechanism as Regulatory Guaranty" in this prospectus.
There is no limit or cap on level of nuclear asset-recovery charges:	Under the irrevocable financing order, the Florida Commission guarantees it will act, as directed by the Financing Act, to implement the true-up mechanism for making any adjustments that are necessary to correct for any overcollection or undercollection of the nuclear asset-recovery charges or to otherwise ensure the timely payment of principal of and interest on the bonds when due and other financing costs and other required amounts and charges payable in connection with the bonds. See "Description of the Series A Bonds—Events of Default; Rights Upon Event of Default" in this prospectus.
Credit/security for the bonds:	The bonds are secured by nuclear asset-recovery property, by funds on deposit in the collection account, including the general subaccount, the capital subaccount and the excess funds subaccount, by our rights under the various transaction documents, by our right to compel the servicer to file for and obtain true-up adjustments, and by all payments on or under the pledged collateral and by all proceeds in respect to the pledged collateral. See "Security for the Series A Bonds" in this prospectus. Nuclear Asset-Recovery property is a present property right created by the Financing Act and the financing order and is protected by the state pledge described in this prospectus. See "The Nuclear Asset-Recovery Property and the Financing Act" in this prospectus.

In general, nuclear asset-recovery property permits a nuclear asset-recovery charge, also known as a **ratepayer obligation charge** or **ROC**, to be:

1. paid on a joint and several basis by all existing and future customers (individuals, corporations, other business entities, the State of Florida and other federal, state and local governmental entities) receiving transmission or distribution service from DEF or its successors or assignees under FPSC-approved rate schedules or under special contracts, even if a customer elects to purchase electricity from an alternative electric supplier following a fundamental change in regulation of public utilities in Florida;

2. collected by DEF, as servicer, and remitted to the indenture trustee daily to provide for payments in respect of the bonds; and

3. adjusted at least semi-annually (and quarterly after the scheduled final payment date for the latest maturing bond), and more frequently as needed to ensure recovery of revenues sufficient to pay principal of and interest on the bonds when due and other financing costs and other required amounts and charges payable in connection with the bonds.

The nuclear asset-recovery property securing the bonds consists of all rights and interests of DEF under the financing order. The nuclear asset-recovery property is being sold to us by DEF in connection with the issuance of the bonds.

- Nuclear asset-recovery property is not a receivable, and the bonds are not secured by a pool of receivables.

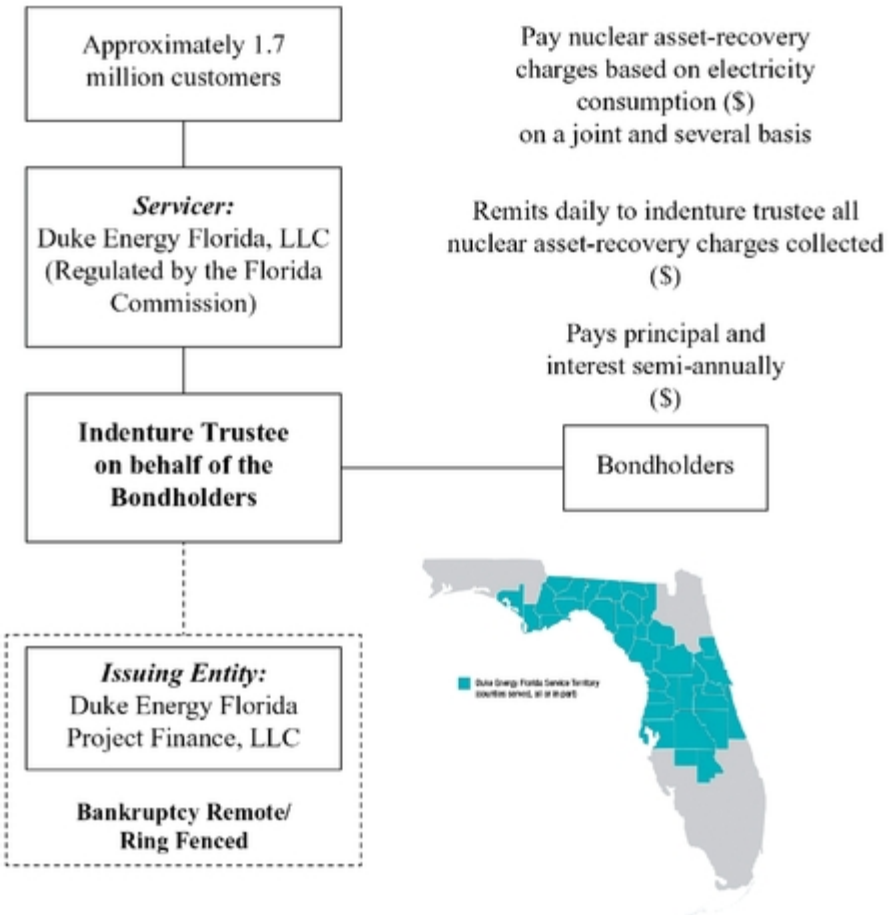
- The bonds are corporate securities and are not asset-backed securities as defined by the SEC in governing regulations Item 1101 of Regulation AB.

Nuclear asset-recovery property includes the right to impose, bill, collect and receive nuclear asset-recovery charges from all existing and future customers receiving transmission or distribution service from DEF or its successors or assignees under FPSC-approved rate schedules or under special contracts to be paid on a joint and several basis. Nuclear asset-recovery property includes the right to a mandatory true-up mechanism that at least semi-annually, and more frequently as needed, adjusts the nuclear asset-recovery charges to levels necessary to ensure recovery of revenues sufficient to timely pay principal of and interest on the bonds when due and other financing costs and other required amounts and charges payable in connection with the bonds. With respect to the foregoing, interest is due on each payment date and principal is due upon the final maturity date for each WAL. It also includes the right to receive all revenues, collections, claims, rights to payments, payments, money, or proceeds arising from DEF's rights and interests under the financing order.

Under the irrevocable financing order, the Florida Commission guarantees it will act, as directed by the Financing Act, to implement the true-up mechanism for making any adjustments that are necessary to correct for any overcollection or undercollection of the nuclear asset-recovery charges or to otherwise ensure the timely payment of principal of and interest on the bonds when due and other financing costs and other required amounts and charges payable in connection with the bonds.

Credit enhancement for the bonds will be provided by the true-up mechanism, as well as by the capital subaccount. The primary purpose of the excess funds subaccount is not to provide credit enhancement for the bonds but to hold funds collected in amounts that were more than necessary to pay current debt service. However, amounts in the excess funds subaccount may be used to make debt service payments on the bonds when needed.

Allocation and flow of funds: The following chart represents a general summary of the flow of funds.



DEF service area: Approximately 1.7 million customers, 13,000 square miles, operating in all or part of 35 Florida counties

Generally, DEF's transmission and distribution customers will pay nuclear asset-recovery charges and all other components of their monthly electricity bills to DEF.

On each payment date, the indenture trustee will pay all amounts on deposit in the general subaccount of the collection account in the following order of priority:

1. payment of the indenture trustee's fees, expenses and outstanding indemnity amounts in an amount not to exceed annually $500,000 in the then current calendar year;

2. payment of the servicing fee plus any unpaid servicing fees from prior payment dates;

3. payment of the administration fee to the extent due on that payment date and of the fees of our independent manager plus any unpaid administration or management fees from prior payment dates;

4. payment of all of our other ordinary periodic operating expenses;

5. payment of the interest then due, including any past-due interest;

6. payment of the principal required to be paid on the final maturity date for each WAL or as a result of acceleration upon an event of default;

7. payment of the principal then scheduled to be paid in accordance with the expected sinking fund schedule, including any previously unpaid scheduled principal, paid pro rata among the bonds if there is a deficiency;

8. payment of any of our remaining unpaid operating expenses and any remaining amounts owed pursuant to the basic documents;

9. replenishment of any amounts drawn from the capital subaccount;

10. release to DEF of an amount equal to the rate of return on the amount contributed to the capital subaccount, including any portion of such rate of return for any prior payment date that has not yet been paid, so long as no event of default has occurred and is continuing; and

11. allocation of the remainder collected, if any, to the excess funds subaccount for future payments.

See "Security for the Series A Bonds—How Funds in the Collection Account Will Be Allocated" in this prospectus. The servicing fee referred to in clause (2) is described in "The Servicing Agreement", and the amount of the administrative fee referred to in clause (3) above is described in "Issuing Entity—The Administrative Agreement" below.

Issuance of additional nuclear asset-recovery bonds by us:	We have been organized to serve as a special purpose project finance subsidiary of DEF. As authorized by the financing order, our organizational documents as well as the transaction documents supporting the bonds give us the authority and flexibility to issue additional nuclear asset-recovery bonds in future transactions, with the approval of the Florida Commission. As a result, we may acquire additional nuclear asset-recovery property and issue one or more additional series of nuclear asset-recovery bonds that are supported by such additional and separate nuclear asset-recovery property or other collateral. For example, such future financings may include additional series of nuclear asset-recovery bonds to finance additional nuclear asset-recovery costs at CR3. If authorized by the Florida Commission, such future financings may include nuclear asset-recovery bonds issued to finance costs, if any, which result from (1) capital costs of dry cask storage facilities at CR3, (2) additional funds needed to fund the CR3 Nuclear Decommissioning Trust in support of decommissioning CR3 or (3) costs which result from a new requirement adopted after October 14, 2015, by the United States Nuclear Regulatory Commission, Federal Energy Commission, or North American Electric Reliability Corporation that are applicable industry wide or generally applicable to shut down nuclear plants or (4) any other CR3 Force Majeure event, as defined in the "Glossary" of this prospectus. Each series of nuclear asset-recovery bonds that may be issued will be backed by separate nuclear asset-recovery property we acquire for the separate purpose of repaying that series. Any new series of such securities may include terms and provisions that would be unique to that particular series of nuclear asset-recovery bonds. Each series that we may issue will have the benefit of a true-up mechanism. However, we may not issue additional nuclear asset-recovery bonds unless the rating agency condition for the bonds, as defined in the "Glossary", has been satisfied. It will be a condition of issuance for each series of nuclear asset-recovery bonds that the new series receive a rating or ratings as required by the applicable financing order. In addition, we may not issue additional nuclear asset-recovery bonds (other than additional nuclear asset-recovery bonds under the financing order) unless each of the following conditions is satisfied: • except for additional nuclear asset-recovery bonds authorized under the financing order, DEF requests and receives another financing order from the Florida Commission;

- each series has recourse only to the nuclear asset-recovery property and funds on deposit in the trust accounts held by the indenture trustee with respect to that series, is nonrecourse to our other assets and does not constitute a claim against us if revenue from the ROCs and funds on deposit in the trust accounts with respect to that series are insufficient to pay such other series in full;

- the indenture trustee and the rating agencies then rating any series of our outstanding nuclear asset-recovery bonds are provided an opinion of a nationally recognized law firm experienced in such matters to the effect that such issuance would not result in our substantive consolidation with DEF and that there has been a true sale of the nuclear asset-recovery property with respect to such series, subject to the customary exceptions, qualifications and assumptions contained therein;

- transaction documentation for the other series provides that holders of the nuclear asset-recovery bonds of the other series will not file or join in filing of any bankruptcy petition against us;

- if holders of such other series are deemed to have any interest in any of our assets that are dedicated to the bonds, holders of such other nuclear asset-recovery bonds must agree that their interest in the assets that are dedicated to the bonds is subordinate to claims or rights of holders of the bonds;

- each series will have its own bank accounts or trust accounts; and

- each series will bear its own indenture trustee fees, servicer fees and pro rata portion administration fees due under the administration agreement.

Allocation among series:	The bonds will not be subordinated in right of payment to any other series of nuclear asset-recovery bonds. Each series of nuclear asset-recovery bonds will be secured by its own nuclear asset-recovery property, which will include the right to impose, bill, collect and receive nuclear asset-recovery charges calculated in respect of that series, and the right to impose interim and annual true-up adjustments to correct overcollections or undercollections in respect of that series. Each series will also have its own collection account, including any related subaccounts, into which revenue from the nuclear asset-recovery charges relating to that series will be deposited and from which amounts will be withdrawn to pay the related series of nuclear asset-recovery bonds. Holders of one series of nuclear asset-recovery bonds will have no recourse to collateral for a different series. Each series that we may issue will also have the benefit of a true-up mechanism. The administration fees, independent manager fees and other operating expenses payable by us on a payment date will be assessed to each series of nuclear asset-recovery bonds on a pro rata basis, based upon the respective outstanding principal amounts of each series. See "Security for the Series A Bonds—Description of Indenture Accounts" and "—How Funds in the Collection Account Will Be Allocated" in this prospectus. Although each series of nuclear asset-recovery bonds will have its own nuclear asset-recovery property, nuclear asset-recovery charges relating to the bonds and nuclear asset-recovery charges relating to any other series of nuclear asset-recovery bonds will be collected through single electricity bills to each electric service customer. The nuclear asset-recovery charges for each series will not be separately identified on customer electricity bills, although customer electricity bills will state that a portion of the electricity bill consists of the rights to the nuclear asset-recovery charges that have been sold to us. In the event a customer does not pay in full all amounts owed under any bill including nuclear asset-recovery charges, each servicer is required to allocate any resulting shortfalls in nuclear asset-recovery charges ratably based on the amounts of nuclear asset-recovery charges owing in respect of the bonds, any amounts owing to any other series and amounts owing to any other subsequently created special-purpose subsidiaries of the utilities which issue nuclear asset-recovery bonds. See "The Servicing Agreement—Remittances to Collection Account" in this prospectus.
ERISA eligible:	Yes; please read "ERISA Considerations" in this prospectus.
Credit risk retention requirements:	The bonds are not subject to the 5% risk retention requirements imposed by Section 15G of the Exchange Act (added by Section 941 of the Dodd-Frank Wall Street Reform and Consumer Protection Act).

	In addition, we and DEF believe that the bonds will not be subject to the 5% risk retention requirement imposed by the European Union Capital Requirements Regulation (Regulation (EU) No 575/2013). For the purposes of the European Union's risk retention rules, we and DEF believe the issue of the bonds does not fall within the definition of a "securitisation" as the credit risk associated with exposure is not tranched. We and DEF believe, therefore, that the EU risk retention rules do not apply to the issue of the bonds.
International Risk Weighting	**We cannot assure you of the risk weighting or other treatment of the bonds under any national law, regulation or policy implementing the international regulatory framework for banking institutions known as Basel III. You should consult your own professional advisors and, as you see fit, supervisory regulators before making any investment in the bonds.** There are certain factors that may be considered by banks in their risk weighting analysis for regulatory capital purposes, including in certain countries other than the United States the rating category of the bonds determined by major credit rating agency. See "Risk Weighting Under Certain International Capital Guidelines" in this prospectus.
Our legal and covenant defeasance options:	We may, by making certain deposits in trust and meeting specified conditions, at any time, terminate all of its obligations under the indenture and the series supplement with respect to the bonds or its obligations to comply with some of the covenants in the indenture and the series supplement, including some of the covenants described under "Description of the Series A Bonds—Covenants of DEF Project Finance" in this prospectus. See "Description of the Series A Bonds—DEF Project Finance's Legal and Covenant Defeasance Options" in this prospectus.
Expected settlement date:	Settling flat. DTC, Clearstream and Euroclear. June 22, 2016.
Continuing disclosure: surveillance/internet-based information post issuance/dedicated Web address:	Duke Energy Corporation, the parent of DEF, will establish a dedicated web address for the life of the bonds. The principal transaction documents and other information concerning the nuclear asset-recovery charges and security relating to the bonds will be posted at such web address, which is currently located at www.duke-energy.com.

The bonds are not asset-backed securities as defined by the SEC in governing regulations Item 1101 of Regulation AB, and neither we nor the depositor is an asset-backed issuer. However, we plan to file with the SEC required periodic and current reports related to the bonds consistent with the disclosure and reporting regime established in Regulation AB and will also post those periodic and current reports at a website associated with DEF or DEF's affiliates.

Risk factors: **You should consider carefully the risk factors beginning on page 21 of this prospectus before you invest in the bonds.**

through (4) above) will become due and payable prior to the next payment date, and setting forth the amount and nature of such operating expense, as well as any supporting documentation that the indenture trustee may reasonably request, the indenture trustee, upon receipt of such information will make payment of such operating expenses on or before the date such payment is due from amounts on deposit in the general subaccount, the excess funds subaccount and the capital subaccount in that order and only to the extent required to make such payment.

Right of Foreclosure

Section 366.95(5)(b)6. of the Financing Act provides that if an event of default or termination occurs under the bonds, the bondholders or their representatives, as secured parties, may foreclose or otherwise enforce the lien on the nuclear asset-recovery property securing such bonds as if they were a secured party under Article 9 of the UCC, and that a court may order that amounts arising from that nuclear asset-recovery property be transferred to a separate account for the holder's benefit, to which their lien and security interest will apply. Upon application by or on behalf of an indenture trustee to a circuit court in Florida, such court shall order sequestration and payment to the indenture trustee of revenues arising from the related nuclear asset-recovery property.

State Pledge

The state pledge in the Financing Act is described under "The Nuclear Asset-Recovery Property and the Financing Act—The Financing Act Provides for the Recovery of Nuclear Asset-Recovery Costs and the Issuance of Nuclear Asset-Recovery Bonds—The Financing Act Contains a State Pledge" in this prospectus. The bondholders and the indenture trustee will be entitled to the benefit of the state pledge and we are authorized to and will include the state pledge on the bonds. We acknowledge that any purchase by a bondholder of a nuclear asset-recovery bond is made in reliance on the state pledge.

WEIGHTED AVERAGE LIFE AND YIELD CONSIDERATIONS FOR THE BONDS

The actual amount of principal and interest payments in respect of the bonds on each semi-annual payment date of each WAL designation of the bonds and the weighted average life thereof will depend on the timing of receipt of nuclear asset-recovery charges and the implementation of the true-up mechanism. The aggregate amount of nuclear asset-recovery charges collected and the rate of principal amortization depends, in part, on energy consumption and the rate of delinquencies and write-offs. The nuclear asset-recovery charges are required to be adjusted at least every six months based in part on the actual rate of collected nuclear asset-recovery charges. However, we can give no assurance that the servicer will forecast accurately actual electricity consumption and the rate of delinquencies and write-offs or implement adjustments to the nuclear asset-recovery charges so as to cause nuclear asset-recovery charges to be collected at any particular rate. Please read "Risk Factors—Servicing Risks—Inaccurate forecasting of electric consumption or collections might reduce scheduled payments on the bonds" and "DEF's Financing Order—FPSC-Guaranteed True-Up Mechanism".

If the servicer collects nuclear asset-recovery charges at a slower rate than forecast during the period of time between mandatory semi-annual true-up adjustments and does not implement an interim true-up adjustment, the bonds may be retired later than scheduled. The servicer, however, may implement a true-up at any time it believes the slower collections may affect the timely payment of principal of and interest on the bonds on a scheduled payment date prior to the mandatory semi-annual true-up adjustment.

No prepayment is permitted. Except in the event of an acceleration of the final payment date of the bonds after an event of default, the bonds will not be paid at a rate faster than that contemplated in the expected sinking fund schedule for each WAL of the bonds even if the receipt of collected nuclear asset-recovery charges is greater than anticipated. Instead, receipts in excess of the amounts necessary to pay debt service on the bonds in accordance with the applicable expected sinking fund

schedules, to pay related fees and expenses and to fund subaccounts of the related collection account will be allocated to the excess funds subaccount. Amounts on deposit in the excess funds subaccount will be taken into consideration in calculating the next true-up adjustment.

Upon an acceleration, due to the nature of our business, payment of principal of the bonds will only be made as funds become available. Please read "Risk Factors—Risk Associated with the Unusual Nature of the Nuclear Asset-Recovery Property—Foreclosure of the indenture trustee's lien on the nuclear asset-recovery property for the bonds might not be practical, and acceleration of the bonds before maturity might result in your investment being repaid either earlier or later than expected" and "Risk Factors—You may experience payment delays as a result of limited sources of payment for the bonds and limited credit enhancement".

Sensitivity Analysis

Weighted Average Life

Weighted average life refers to the average amount of time from the date of issuance of a WAL designation of bonds that such bonds will remain outstanding. The timing of principal and interest payments on the bonds will depend on the timing of the servicer's receipt of nuclear asset-recovery charges from customers.

The weighted average life table below illustrates whether there is risk to bondholders of a material weighted average life extension of each WAL designation.

The table shows changes from the expected weighted average life of each WAL designation of bonds assuming actual future electricity consumption and related charge collections varies from DEF's forecast of future electricity consumption and related charge collections (the forecast variance) of 5% (1.3 standard deviations from the forecast variance mean) or 15% (4.0 standard deviations from the forecast variance mean) during each payment period.

The weighted average life table below illustrates that the aggregate payment of principal of and interest on the bonds and the timing of such payments are not expected to change materially over the life of the bonds, based on the assumptions we have made.

		Effect on Weighted Average Life (Rounded*) of Change in Forecast Variance	
		–5% (1.3 Standard Deviations from Forecast Variance Mean)	–15% (4.0 Standard Deviations from Forecast Variance Mean)
Series A Bonds	Expected Weighted Average Life (yrs)	Weighted Average Life (yrs)	Weighted Average Life (yrs)
Series A 2018	2.0	2.0	2.0
Series A 2021	5.0	5.0	5.1
Series A 2026	10.0	10.0	10.0
Series A 2032	15.2	15.2	15.3
Series A 2035	18.7	18.7	18.8

* Number is rounded to 1/10th of one year

Sensitivity to Credit Risk

A stress case analysis examined the maximum amount of forecast variance that could occur without causing an event of default due to insufficient funds available to pay all principal at final maturity for each WAL designation or insufficient funds available to pay interest on each payment date and expense obligations when due.

For an event of default to occur with respect to any such payment due under the indenture, the forecast variance for the forecast period leading up to such payment would need to be greater than minus 60%, or more than 16 standard deviations from the forecast variance mean.

For there not to be enough funds available to pay principal at final maturity for each WAL designation, interest on each payment date and expense obligations when due, our stress case analysis demonstrated that there would need to be unexpected, extensive and persistent drops in electricity consumption or increases in defaults or write offs among electricity consumers that occur in each forecast period prior to the relevant payment date.

We are not aware of any practical circumstance where such unexpected, extensive and persistent drops in the consumption of electricity or increases in defaults and write offs of that magnitude could occur in the DEF service territory. For comparison, during the most recent 10 years, DEF's mean annual forecast variance was minus 0.16% and the largest unfavorable annual forecast variance was minus 6.53%. See "Risk Factors", in particular "—Servicing Risks—Inaccurate forecasting of electric consumption or collections might reduce scheduled payments on the bonds", and "Cautionary Statement Regarding Forward-Looking Statements" in this prospectus.

Figure 2. DEF service area: Approximately 1.7 million customers, 13,000 square miles, operating in all or part of 35 Florida counties

Assumptions

In preparing the analysis above, the following assumptions, among others, have been made:

(i)
the unfavorable forecast variance stays constant over the life of the bonds;

(ii)
the servicer makes timely and accurate semi-annual true-up adjustments (and quarterly following the last scheduled final payment date), but makes no interim true-up adjustments;

(iii)
for purposes of setting initial nuclear asset-recovery charges, the net charge-off rate as a percentage of billed revenue and average days sales outstanding per customer bill is each assumed to equal DEF's average (mean) for the most recent 10 years;

(iv)
for purposes of setting subsequent nuclear asset-recovery charges, and for purposes of calculating actual nuclear asset-recovery charge collections, net charge-off rate as a percentage of billed revenue and the average days sales outstanding per customer bill are both held constant at DEF's maximum (most unfavorable) for the most recent 10 years;

(v)
during the first payment period, interest will accrue for approximately 9 months and the nuclear asset-recovery charges will be collected for approximately 8 months;

(vi)
there is no acceleration of the final maturity date of the bonds; and

(vi)
the principal amounts and interest rates of the bonds of each WAL designation represent estimates based on current market conditions. Other than as discussed above, there can be no assurance that the weighted average lives of or the events of default with respect to the bonds will be as shown.

Concerning the true-up mechanism through which any delinquencies or under-collections in one customer rate class—for any reason—will be taken into account in the application of the true-up mechanism to adjust the nuclear asset-recovery charges for all customers of DEF, for additional information see "DEF's Financing Order—FPSC-Guaranteed True-Up Mechanism" in this prospectus.

Concerning the broad-based nature of the nuclear asset-recovery charge on a basic and essential commodity, electricity, for additional information see "DEF's Financing Order—Nuclear Asset-Recovery Charges" in this prospectus.

Concerning the non-bypassability of the charges, for additional information see "The Nuclear Asset-Recovery Property and the Financing Act—The Financing Act Provides for the Recovery of Nuclear Asset-Recovery Costs and the Issuance of the Bonds—Transmission and Distribution Customers Cannot Avoid Nuclear Asset-Recovery Charges-Nonbypassable" in this prospectus.

Concerning the State Pledge, for additional information see "Security for the Series A Bonds—State Pledge" and "DEF's Financing Order—FPSC-Guaranteed True-Up Mechanism—FPSC-Guaranteed True-Up Mechanism and State Pledge" in this prospectus.

Exhibit G

Purpose	State(s)
Unrecovered costs of nuclear plant retired early	Florida
Buydown of high-cost PPAs	New Hampshire
Deferred balances (regulatory assets)	New Jersey Maryland Ohio West Virginia
Stranded costs in connection with electric industry deregulation	Pennsylvania Texas New Hampshire Illinois Montana Massachusetts New Jersey Michigan Connecticut Louisiana
Storm recovery costs	Florida Louisiana Texas Arkansas
Costs of new pollution control equipment at existing electric generating facilities	West Virginia Wisconsin
Costs of new renewable distributed generation	Hawaii

Exhibit H

Securitization of PG&E UOG with typical 4-Tranche structure

($000)

	Int. Rate (%):		3.91		3.15			3.75			4.02			4.17		
	WAL (yrs.):	11.70			4.00			10.00			15.00			18.87		
Payment Date	Aggregate Bond Balance	Total Principal Payment	Total Interest Payment	A-1 Principal Balance	Princ. Pmt.	Interest Pmt.	A-2 Principal Balance	Princ. Pmt.	Interest Pmt.	A-3 Principal Balance	Princ. Pmt.	Interest Pmt.	A-4 Principal Balance	Princ. Pmt.	Interest Pmt.	Total Revenue Requirement[1]
12/15/2018	4,649,222	-		1,218,000	-		1,181,000	-		1,235,000	-		1,015,222	-		
12/15/2019	4,484,344	164,878	174,557	1,053,122	164,878	38,334	1,181,000	-	44,291	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2020	4,314,277	170,067	169,368	883,056	170,067	33,145	1,181,000	-	44,291	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2021	4,138,858	175,419	164,016	707,636	175,419	27,792	1,181,000	-	44,291	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2022	3,957,918	180,940	158,495	526,696	180,940	22,271	1,181,000	-	44,291	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2023	3,771,283	186,635	152,800	340,061	186,635	16,577	1,181,000	-	44,291	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2024	3,578,774	192,509	146,926	147,553	192,509	10,703	1,181,000	-	44,291	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2025	3,380,207	198,568	140,867	-	147,553	4,644	1,129,985	51,015	44,291	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2026	3,175,082	205,125	134,310	-	-	-	924,860	205,125	42,377	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2027	2,962,265	212,817	126,617	-	-	-	712,043	212,817	34,685	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2028	2,741,466	220,799	118,636	-	-	-	491,244	220,799	26,704	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2029	2,512,387	229,079	110,356	-	-	-	262,165	229,079	18,423	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2030	2,274,716	237,670	101,765	-	-	-	24,495	237,670	9,832	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2031	2,028,133	246,584	92,851	-	-	-	-	24,495	919	1,012,911	222,089	49,613	1,015,222	-	42,320	**339,435**
12/15/2032	1,771,709	256,424	83,011	-	-	-	-	-	-	756,487	256,424	40,691	1,015,222	-	42,320	**339,435**
12/15/2033	1,504,984	266,725	72,710	-	-	-	-	-	-	489,762	266,725	30,390	1,015,222	-	42,320	**339,435**
12/15/2034	1,227,544	277,440	61,995	-	-	-	-	-	-	212,322	277,440	19,675	1,015,222	-	42,320	**339,435**
12/15/2035	938,958	288,586	50,849	-	-	-	-	-	-	-	212,322	8,530	938,958	76,264	42,320	**339,435**
12/15/2036	638,664	300,294	39,141	-	-	-	-	-	-	-	-	-	638,664	300,294	39,141	**339,435**
12/15/2037	325,852	312,812	26,623	-	-	-	-	-	-	-	-	-	325,852	312,812	26,623	**339,435**
12/15/2038	-	325,852	13,583	-	-	-	-	-	-	-	-	-	-	325,852	13,583	**339,435**
	Total Principal	4,649,222	1,607,903		1,218,000	153,466		1,181,000	442,974		1,235,000	744,255		1,015,222	798,782	**6,788,698**
	less Xaction Cost	(92,984)														
	Asset	4,556,237														

(1) Excluding franchise fees of $75,506 which are assumed paid by the utility on bond-related revenues.

Proprietary

Securitization of PG&E UOG excluding fossil with typical 4-Tranche structure

($000)

	Int. Rate (%):		3.91			3.15			3.75			4.02			4.17			
	WAL (yrs.):	11.70			4.00			10.00			15.00			18.87			
Payment Date	Aggregate Bond Balance	Total Principal Payment	Total Interest Payment	A-1 Principal Balance	Princ. Pmt.	Interest Pmt.	A-2 Principal Balance	Princ. Pmt.	Interest Pmt.	A-3 Principal Balance	Princ. Pmt.	Interest Pmt.	A-4 Principal Balance	Princ. Pmt.	Interest Pmt.	Total Revenue Requirement[1]
12/15/2018	3,883,780	-		1,017,000	-		986,000	-		1,032,000	-		848,780	-		
12/15/2019	3,746,047	137,733	145,818	879,267	137,733	32,006	986,000	-	36,975	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2020	3,603,979	142,068	141,483	737,199	142,068	27,671	986,000	-	36,975	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2021	3,457,440	146,539	137,012	590,661	146,539	23,200	986,000	-	36,975	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2022	3,306,290	151,150	132,401	439,510	151,150	18,588	986,000	-	36,975	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2023	3,150,383	155,907	127,644	283,603	155,907	13,832	986,000	-	36,975	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2024	2,989,569	160,814	122,737	122,790	160,814	8,925	986,000	-	36,975	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2025	2,823,695	165,874	117,677	-	122,790	3,864	942,915	43,085	36,975	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2026	2,652,341	171,354	112,197	-	-	-	771,561	171,354	35,359	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2027	2,474,561	177,780	105,771	-	-	-	593,781	177,780	28,933	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2028	2,290,114	184,447	99,104	-	-	-	409,334	184,447	22,267	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2029	2,098,750	191,363	92,187	-	-	-	217,971	191,363	15,350	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2030	1,900,211	198,540	85,011	-	-	-	19,431	198,540	8,174	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2031	1,694,226	205,985	77,566	-	-	-	-	19,431	729	845,446	186,554	41,456	848,780	-	35,381	**283,551**
12/15/2032	1,480,019	214,207	69,344	-	-	-	-	-	-	631,239	214,207	33,962	848,780	-	35,381	**283,551**
12/15/2033	1,257,206	222,812	60,739	-	-	-	-	-	-	408,427	222,812	25,358	848,780	-	35,381	**283,551**
12/15/2034	1,025,443	231,763	51,788	-	-	-	-	-	-	176,664	231,763	16,407	848,780	-	35,381	**283,551**
12/15/2035	784,370	241,073	42,478	-	-	-	-	-	-	-	176,664	7,097	784,370	64,409	35,381	**283,551**
12/15/2036	533,516	250,855	32,696	-	-	-	-	-	-	-	-	-	533,516	250,855	32,696	**283,551**
12/15/2037	272,204	261,312	22,239	-	-	-	-	-	-	-	-	-	272,204	261,312	22,239	**283,551**
12/15/2038	0	272,204	11,347	-	-	-	-	-	-	-	-	-	-	272,204	11,347	**283,551**
Total Principal		3,883,780	1,787,239		1,017,000	128,086		986,000	369,634		1,032,000	621,758		848,780	667,761	**5,671,019**
less Xaction Cost		(77,676)														
Asset		3,806,104														

(1) Excluding franchise fees of $63,075 which are assumed paid by the utility on bond-related revenues.

Proprietary

Securitization of SCE UOG with typical 4-Tranche structure

($000)

	Int. Rate (%):		4.07			3.15			3.81			4.14			4.31		
	WAL (yrs.):	14.94			4.00			11.00			18.00			23.40			
Payment Date	Aggregate Bond Balance	Total Principal Payment	Total Interest Payment	A-1 Principal Balance	Princ. Pmt.	Interest Pmt.	A-2 Principal Balance	Princ. Pmt.	Interest Pmt.	A-3 Principal Balance	Princ. Pmt.	Interest Pmt.	A-4 Principal Balance	Princ. Pmt.	Interest Pmt.	Total Revenue Requirement[1]
12/15/2018	1,476,426	-		276,000	-		375,000	-		460,000	-		365,426	-		
12/15/2019	1,439,012	37,414	57,764	238,586	37,414	8,685	375,000	-	14,298	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2020	1,400,420	38,591	56,586	199,994	38,591	7,507	375,000	-	14,298	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2021	1,360,615	39,806	55,372	160,189	39,806	6,293	375,000	-	14,298	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2022	1,319,556	41,058	54,120	119,130	41,058	5,040	375,000	-	14,298	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2023	1,277,206	42,350	52,828	76,780	42,350	3,749	375,000	-	14,298	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2024	1,233,523	43,683	51,495	33,097	43,683	2,416	375,000	-	14,298	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2025	1,188,466	45,057	50,120	-	33,097	1,041	363,040	11,960	14,298	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2026	1,141,911	46,555	48,623	-	-	-	316,485	46,555	13,842	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2027	1,093,582	48,330	46,848	-	-	-	268,156	48,330	12,067	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2028	1,043,409	50,172	45,005	-	-	-	217,983	50,172	10,224	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2029	991,324	52,085	43,092	-	-	-	165,898	52,085	8,311	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2030	937,252	54,071	41,106	-	-	-	111,826	54,071	6,325	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2031	881,119	56,133	39,045	-	-	-	55,693	56,133	4,264	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2032	822,846	58,273	36,905	-	-	-	-	55,693	2,123	457,420	2,580	19,031	365,426	-	15,750	**95,178**
12/15/2033	762,343	60,503	34,674	-	-	-	-	-	-	396,917	60,503	18,925	365,426	-	15,750	**95,178**
12/15/2034	699,336	63,007	32,171	-	-	-	-	-	-	333,910	63,007	16,422	365,426	-	15,750	**95,178**
12/15/2035	633,723	65,613	29,564	-	-	-	-	-	-	268,297	65,613	13,815	365,426	-	15,750	**95,178**
12/15/2036	565,395	68,328	26,850	-	-	-	-	-	-	199,969	68,328	11,100	365,426	-	15,750	**95,178**
12/15/2037	494,240	71,155	24,023	-	-	-	-	-	-	128,814	71,155	8,273	365,426	-	15,750	**95,178**
12/15/2038	420,141	74,099	21,079	-	-	-	-	-	-	54,715	74,099	5,329	365,426	-	15,750	**95,178**
12/15/2039	342,977	77,164	18,013	-	-	-	-	-	-	-	54,715	2,264	342,977	22,449	15,750	**95,178**
12/15/2040	262,581	80,396	14,782	-	-	-	-	-	-	-	-	-	262,581	80,396	14,782	**95,178**
12/15/2041	178,720	83,861	11,317	-	-	-	-	-	-	-	-	-	178,720	83,861	11,317	**95,178**
12/15/2042	91,245	87,475	7,703	-	-	-	-	-	-	-	-	-	91,245	87,475	7,703	**95,178**
12/15/2043	-	91,245	3,933	-	-	-	-	-	-	-	-	-	-	91,245	3,933	**95,178**
	Total Principal	1,476,426	903,018		276,000	34,731		375,000	157,243		460,000	342,568		365,426	368,477	**2,379,444**
	less Xaction Cost	(29,529)														
	Asset	1,446,897														

(1) Excluding franchise fees of $21,609 which are assumed paid by the utility on bond-related revenues.

Proprietary

Exhibit I

Expected revenue requirements for PG&E UOG with existing capitalization
($000)

WAL (yrs.)	7.34							
	(a)	(b)	(c)		(d)	(e)	(f)	(g)
Year	Beginning Rate Base	Return (a) * WACC	Return on Equity (a) * WCE	After Tax Income (e) + (f) + (g)	Income-Based Taxes (c) * Tax Factor [1]	Annual Amortization	Revenue-Based Fees	Total Revenue Requirement (b)+(d)+(e)+(f)
2019	4,556,237	350,115	245,399	245,399	95,355	437,763	9,824	893,057
2020	4,118,474	316,476	221,821	221,821	86,194	437,763	9,348	849,780
2021	3,680,711	282,837	198,243	198,243	77,032	437,763	8,872	806,503
2022	3,242,948	249,198	174,665	174,665	67,870	437,763	8,395	763,226
2023	2,805,185	215,559	151,087	151,087	58,708	437,763	7,919	719,950
2024	2,367,422	181,920	127,509	127,509	49,547	437,763	7,443	676,673
2025	1,929,660	148,281	103,931	103,931	40,385	236,681	4,731	430,077
2026	1,692,979	130,094	91,184	91,184	35,432	150,503	3,515	319,543
2027	1,542,476	118,528	83,078	83,078	32,282	150,503	3,351	304,664
2028	1,391,974	106,963	74,972	74,972	29,132	150,503	3,188	289,786
2029	1,241,471	95,398	66,866	66,866	25,982	150,503	3,024	274,907
2030	1,090,968	83,833	58,760	58,760	22,832	150,503	2,860	260,029
2031	940,466	72,268	50,653	50,653	19,683	150,503	2,697	245,150
2032	789,963	60,703	42,547	42,547	16,533	150,503	2,533	230,272
2033	639,460	49,138	34,441	34,441	13,383	150,503	2,369	215,393
2034	488,958	37,573	26,335	26,335	10,233	150,503	2,206	200,514
2035	338,455	26,008	18,229	18,229	7,083	150,503	2,042	185,636
2036	187,952	14,443	10,123	10,123	3,934	137,425	1,733	157,535
2037	50,527	3,883	2,721	2,721	1,057	38,867	487	44,294
2038	11,660	896	628	628	244	11,660	142	12,942
Total	33,107,947	2,544,114	1,783,194	1,783,194	692,900	4,556,237	86,679	7,879,931

[1] Tax factor = Composite tax rate/(1-Composite tax rate)

Proprietary

Expected revenue requirements for PG&E UOG excluding fossil with existing capitalization

($000)

WAL (yrs.):	6.81							
	(a)	(b)	(c)		(d)	(e)	(f)	(g)
Year	Beginning Rate Base	Return (a) * WACC	Return on Equity (a) * WCE	After Tax Income (e) + (f) + (g)	Income-Based Taxes (c) * Tax Factor (1)	Annual Amortization	Revenue-Based Fees	Total Revenue Requirement (b)+(d)+(e)+(f)
2019	3,806,104	292,472	204,997	204,997	79,656	398,896	8,576	**779,600**
2020	3,407,208	261,820	183,512	183,512	71,308	398,896	8,142	**740,166**
2021	3,008,312	231,168	162,028	162,028	62,960	398,896	7,708	**700,731**
2022	2,609,416	200,515	140,543	140,543	54,611	398,896	7,274	**661,297**
2023	2,210,520	169,863	119,059	119,059	46,263	398,896	6,840	**621,862**
2024	1,811,624	139,211	97,574	97,574	37,915	398,896	6,407	**582,428**
2025	1,412,729	108,558	76,090	76,090	29,566	197,814	3,736	**339,675**
2026	1,214,915	93,358	65,435	65,435	25,426	111,636	2,563	**232,983**
2027	1,103,279	84,779	59,423	59,423	23,090	111,636	2,441	**221,946**
2028	991,644	76,201	53,410	53,410	20,754	111,636	2,320	**210,910**
2029	880,008	67,622	47,397	47,397	18,417	111,636	2,199	**199,874**
2030	768,372	59,044	41,385	41,385	16,081	111,636	2,077	**188,838**
2031	656,737	50,466	35,372	35,372	13,745	111,636	1,956	**177,802**
2032	545,101	41,887	29,359	29,359	11,408	111,636	1,834	**166,765**
2033	433,465	33,309	23,346	23,346	9,072	111,636	1,713	**155,729**
2034	321,830	24,730	17,334	17,334	6,735	111,636	1,592	**144,693**
2035	210,194	16,152	11,321	11,321	4,399	111,636	1,470	**133,657**
2036	98,558	7,574	5,308	5,308	2,063	98,558	1,203	**109,398**
Total	25,490,016	1,958,729	1,372,892	1,372,892	533,468	3,806,104	70,052	**6,368,354**

(1) Tax factor = Composite tax rate/(1-Composite tax rate)

Proprietary

Expected revenue requirements for SCE UOG with existing capitalization

($000)

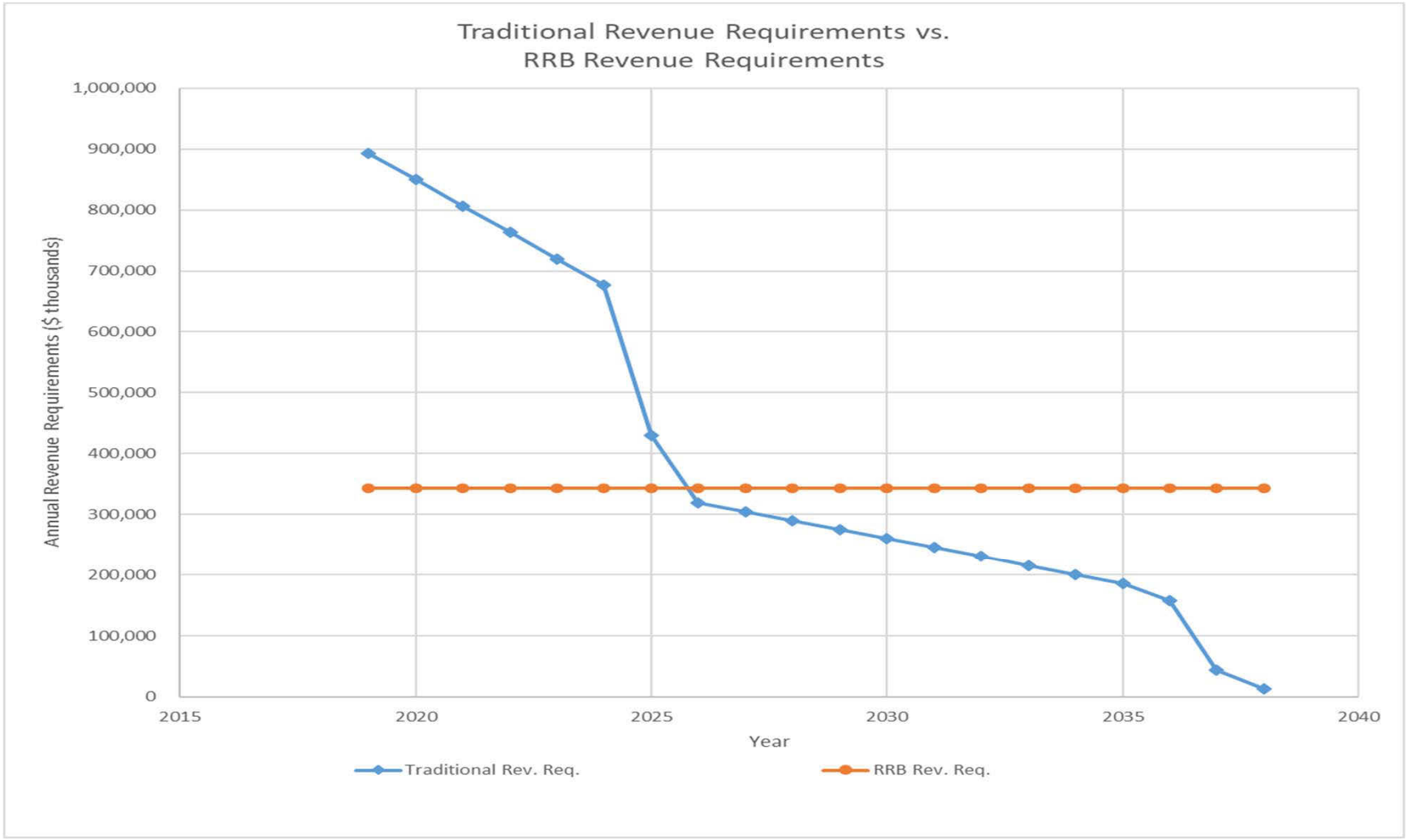
WAL (yrs.):	9.74							
	(a)	(b)	(c)		(d)	(e)	(f)	(g)
Year	Beginning Rate Base	Return (a) * WACC	Return on Equity (a) * WCE	After Tax Income (e) + (f) + (g)	Income-based Taxes (c) * Tax Factor [1]	Annual Amortization	Revenue-based Fees	Total Revenue Requirement (b)+(d)+(e)+(f)
2019	1,446,897	110,097	79,113	79,113	30,741	83,103	2,034	**225,975**
2020	1,363,795	103,774	74,570	74,570	28,976	83,103	1,960	**217,812**
2021	1,280,692	97,450	70,026	70,026	27,210	83,103	1,887	**209,650**
2022	1,197,590	91,127	65,482	65,482	25,444	83,103	1,813	**201,487**
2023	1,114,487	84,804	60,938	60,938	23,679	83,103	1,740	**193,325**
2024	1,031,385	78,480	56,394	56,394	21,913	83,103	1,666	**185,162**
2025	948,282	72,157	51,850	51,850	20,148	83,103	1,593	**177,000**
2026	865,180	65,833	47,306	47,306	18,382	83,103	1,520	**168,837**
2027	782,077	59,510	42,762	42,762	16,616	83,103	1,446	**160,675**
2028	698,975	53,186	38,219	38,219	14,851	83,103	1,373	**152,512**
2029	615,872	46,863	33,675	33,675	13,085	83,103	1,299	**144,350**
2030	532,770	40,540	29,131	29,131	11,319	83,103	1,226	**136,187**
2031	449,667	34,216	24,587	24,587	9,554	77,803	1,104	**122,677**
2032	371,864	28,296	20,333	20,333	7,901	65,438	923	**102,558**
2033	306,426	23,317	16,755	16,755	6,510	65,438	865	**96,130**
2034	240,987	18,337	13,177	13,177	5,120	65,438	807	**89,703**
2035	175,549	13,358	9,599	9,599	3,730	27,857	408	**45,353**
2036	147,692	11,238	8,076	8,076	3,138	18,462	298	**33,136**
2037	129,231	9,833	7,066	7,066	2,746	18,462	282	**31,323**
2038	110,769	8,429	6,057	6,057	2,353	18,462	266	**29,509**
2039	92,308	7,024	5,047	5,047	1,961	18,462	249	**27,696**
2040	73,846	5,619	4,038	4,038	1,569	18,462	233	**25,883**
2041	55,385	4,214	3,028	3,028	1,177	18,462	217	**24,069**
2042	36,923	2,810	2,019	2,019	784	18,462	200	**22,256**
2043	18,462	1,405	1,009	1,009	392	18,462	184	**20,443**
Total	14,087,113	1,071,917	770,255	770,255	299,300	1,446,897	25,593	**2,843,707**

(1) Tax Factor = Composite tax rate/(1-Composite tax rate)

Proprietary

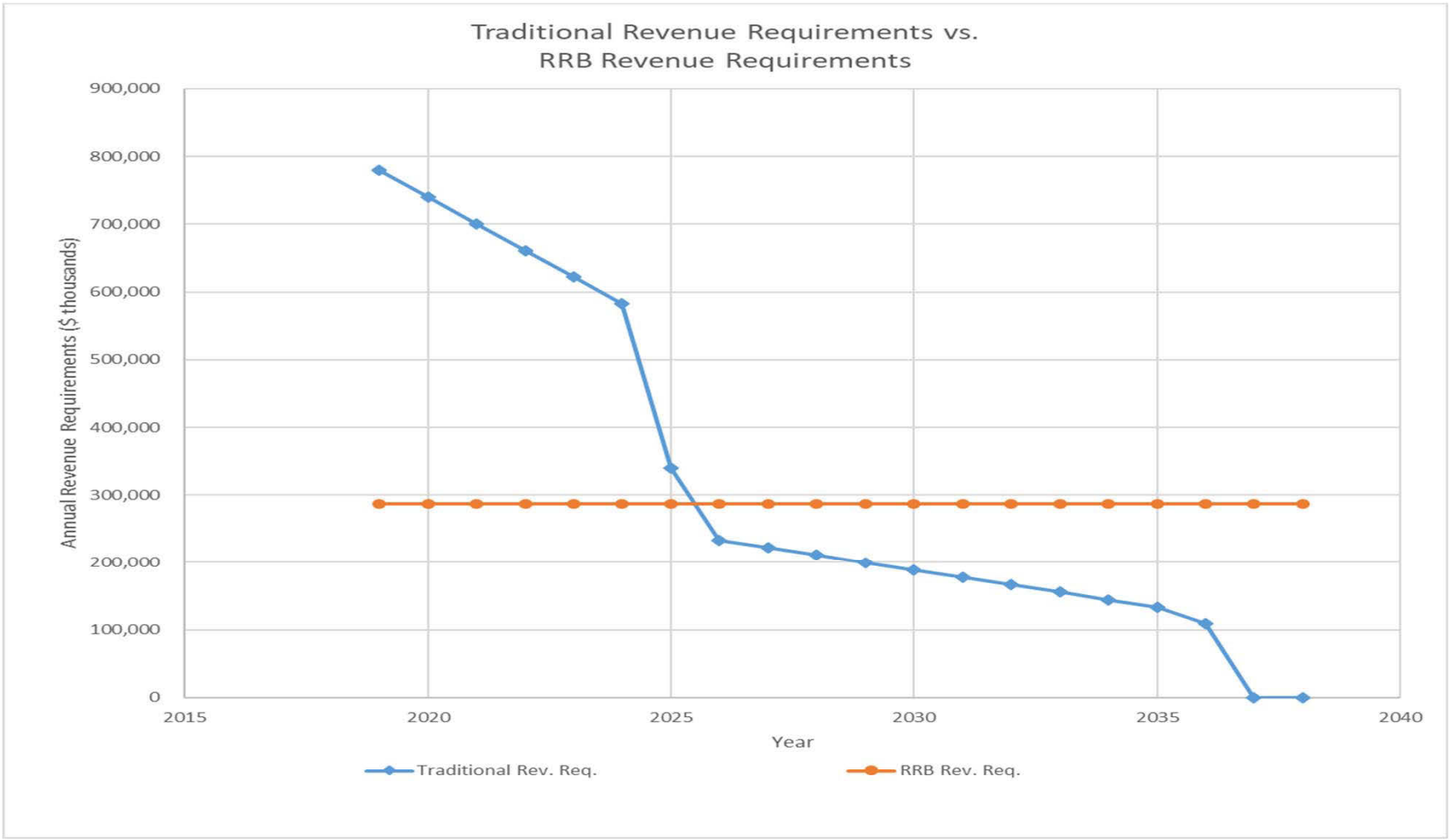
SABER PARTNERS, LLC

PG&E UOG levelized securitization vs declining traditional annual revenue requirements



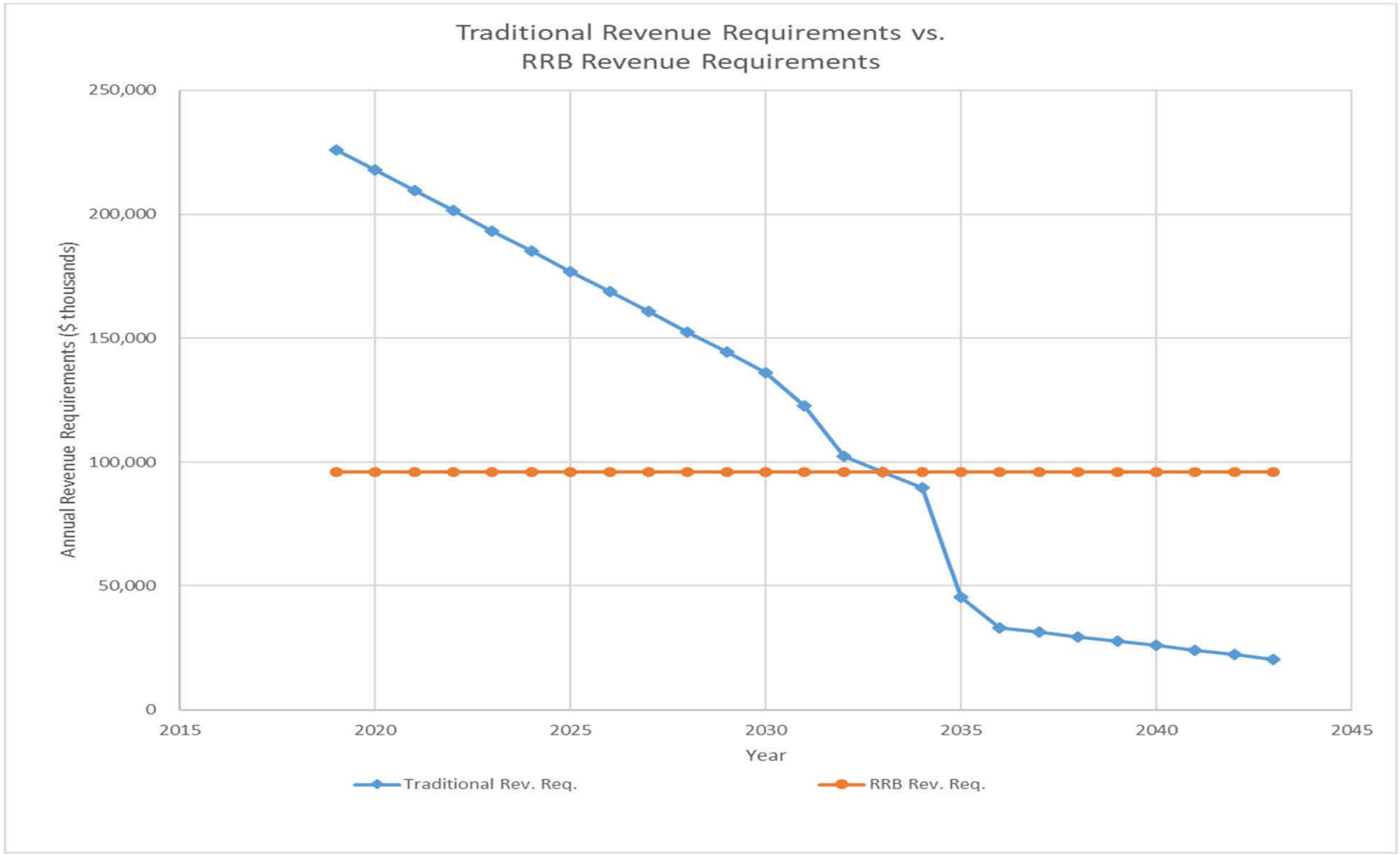
Proprietary

PG&E UOG excluding fossil levelized securitization vs declining traditional annual revenue requirements



Proprietary

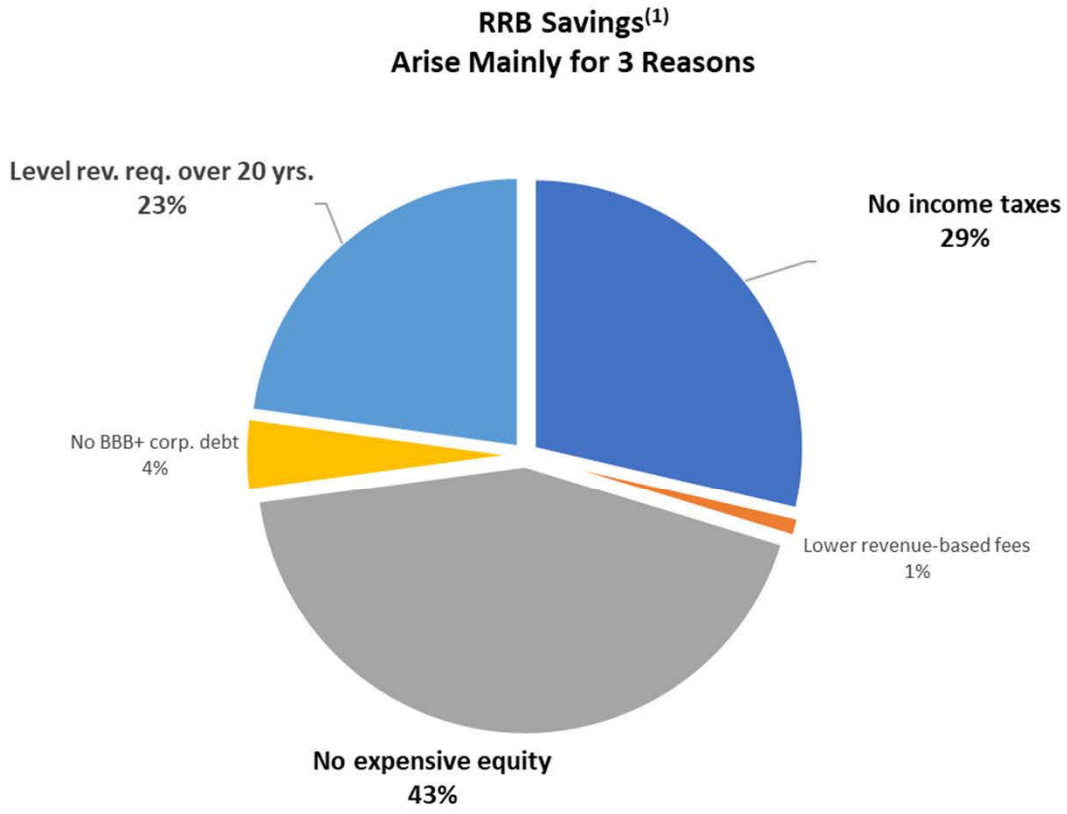
SCE UOG levelized securitization vs declining traditional annual revenue requirements



Proprietary

SABER PARTNERS, LLC

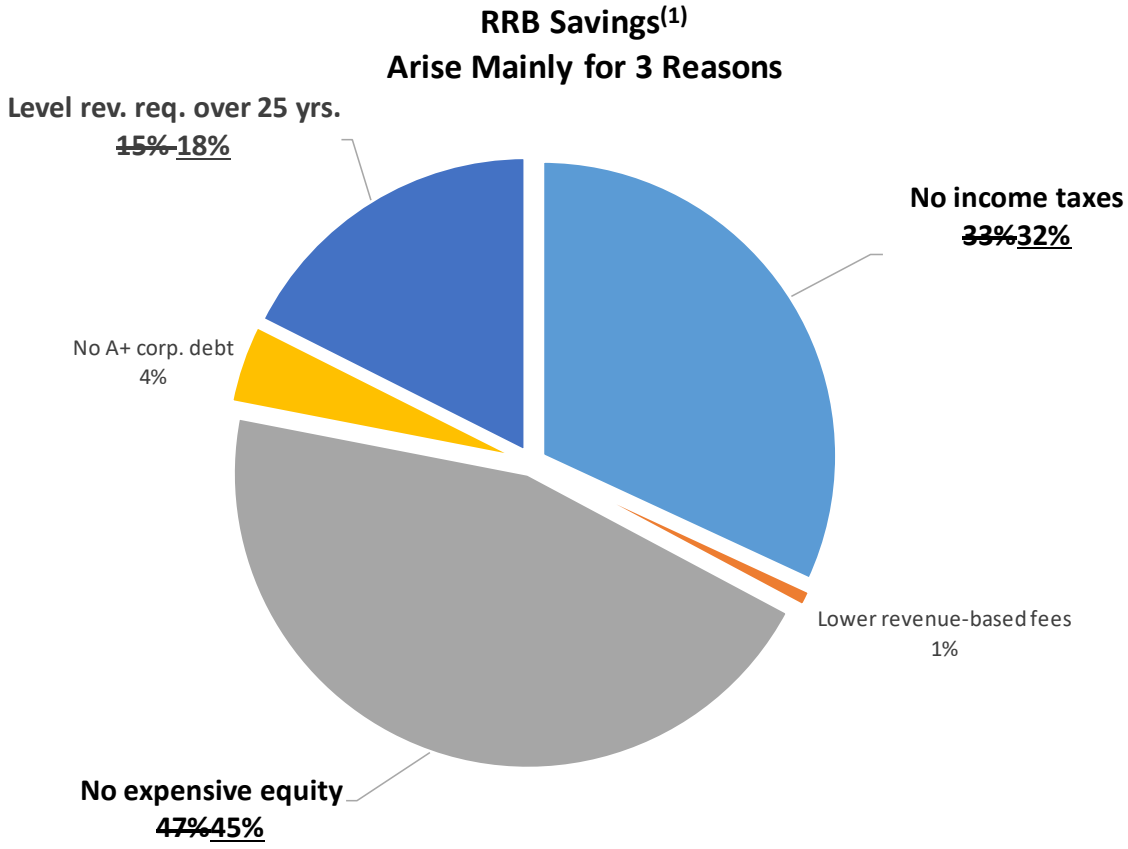
Securitization NPV savings are dependent on factors besides just interest rates – PG&E



(1) Savings net of issuance costs

Proprietary

Securitization NPV savings are dependent on factors besides just interest rates – SCE



(1) Savings net of issuance costs

Proprietary

SABER PARTNERS, LLC

RRB upfront issuance cost as a % of principal amount estimated to be ~1.2% for large deals

Up-Front Costs COMPARISON

Of Recent Investor-Owned Utility Securitization Bonds

Issuer:	New Orleans (estimated)		Consumers (estimated)		DEF (final)	
Date	7/14/2015		7/14/2014		6/15/2016	
Principal Amount:	$98,730,000		$378,000,000		$1,294,290,000	
Itemized Costs						
Variable Costs (based on principa	Amount	% of PA	Amount	% of PA	Amount	% of PA
Rating Agency Fees	315,000	0.33%	373,550	0.32%	1,601,288	0.12%
Underwriters' Fee	350,555	0.36%	1,687,000	0.45%	6,789,530	0.52%
SEC Registration Fee	11,472	0.01%	50,180	0.01%	130,335	0.01%
Variable Cost Subtotal	**$677,027**		**$2,110,730**		**$8,521,153**	
Fixed Costs (independent of principal amount)						
Accountant Fees	225,000		220,000		72,159	
BondCo Set-up Cost	6,000		150,000		3,500	
Company's Financial Advisor/Str	550,000				290,273	
Commissions's Financial Advisor Fees & Expenses					1,600,000	
Commission's Legal Fees & Expenses			95,544		1,171,000	
Legal Fees, incl. Issuer's Counse	1,355,000		3,316,104		3,376,504	
Company's Non-Legal Securitiza	10,000					
Marketing and Miscellaneous Fe	(1,235)		519,860		36,725	
Original Issue Discount	24,090		100,000		51,287	
Printing / Edgarizing Expenses	30,000		30,000		78,033	
Servicer's Set-up Cost	50,000				382,833	
Trustees Counsel Fees and Expe	47,500		20,000		42,900	
Fixed Cost Subtotal	**$2,296,355**		**4,451,508**		**$7,105,214**	
TOTAL UP-FRONT COSTS [1]	**2,973,382**	**3.01%**	**6,562,238**	**1.74%**	**15,626,367** [2]	**1.21%**

(1) Source: Respective transactions FINAL Issuance Advice Letters (IAL), excluding OID

(2) Amount from Appendix A to DEF's IAL updated 8/18/2016

Exhibit L.ii

RRB ongoing costs add about 0.8% NPV

From DEF Attachment 4 Combined Issuance Advice Letter and True Up Adjustment Letter dated 6/16/2016

Duke Energy Florida Principal Amount = $1,294,290,000		
DEF ESTIMATED ANNUAL ONGOING FINANCING COSTS		
Description	**Annual Amount**	
Servicing Fee [1]	$ 647,145	
Return on Invested Capital	201,392	
Subtotal Variable		$ 848,537
Administration Fee	50,000	
Auditor Fees	50,000	
Regulatory Assessment Fees	62,500	
Legal Fees	30,000	
Rating Agency Surveillance Fees	50,000	
Trustee Fees	10,000	
Independent Manager Fees	5,000	
Miscellaneous Fees and Expenses	1,700	
Subtotal Fixed		259,200
TOTAL ESTIMATED ANNUAL ONGOING FINANCING COSTS	**$ 1,107,737**	**$ 1,107,737**

(1) Low end of the range assumes DEF is the servicer (0.05%). However, in most RRB transactions, servicing fees in excess of incremental costto the utility are credited back to ratepayers, so actual cost may be substantially less than assumed.

NPV	**$10,339,435**
NPV as % of Principal	**0.80%**

Exhibit M

Substantial savings are possible from securitization of utility owned generation

	Asset Amt.[1] ($000)	Scheduled Final Maturity (yrs.)	WAL [2] (yrs.)	NPV Savings[3] ($000)	NPV Savings[3] (% of P.A.)
PG&E Utility Owned Generation Securitization					
All Non-CAM[4] Utility Owned Generation (UOG)	4,556,237	20	11.7	1,628,508	35%
All Non-CAM[4] UOG Except Fossil	3,806,104	20	11.7	1,337,475	34%
SCE Utility Owned Generation Securitization					
All Non-CAM[4] Utility Owned Generation (UOG) [5]	1,530,000	25	14.9	589,349	~~41%~~ 40% ~~41%~~

(1) Assuming year end 2018 balances

(2) WAL = weighted average life

(3) Discounted at WACC of 7.69% for PG&E and 7.61% for SCE

(4) Cost Allocation Mechanism

(5) SCE has no fossil Non-CAM generation

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THE WALL STREET JOURNAL.

NEW ENGLAND

ECONOMIC FOCUS

Contract Deal Is Proposed To Aid Vermont Utilities

By Andrew Caffrey
Staff Reporter of The Wall Street Journal

The Vermont utility industry's efforts to resolve one of its expensive and thorny electricity issues may be back on track.

A private nonprofit corporation that facilitates the buying and selling of alternative power says it's beginning to work on a deal to either refinance or buy out altogether the high-priced electricity contracts it has with the Vermont-based independent producers that own those generation facilities.

The company, **Vepp** Inc., which stands for Vermont Electric Power Producers, two weeks ago hired Wall Street investment firm Prudential Securities Inc. to draw up proposals to float $150 million to $200 million in bonds. As proposed, the bonds would be repaid with special surcharges on Vermont utility bills.

Proceeds would be used to either buy out all or a portion of the long-term contracts the producers have with the utilities, or to refinance the producers' debt at lower rates, allowing them to cut prices as well.

"There is progress," says John Spencer, Vepp's executive director. "Everyone involved has come to the realization that this type of method is in everyone's best interest."

The 20 small power plants, mostly hydroelectric projects, are a vestige of the 1980s, when the Carter Administration promoted cheaper home-grown alternative energy sources in the face of oil shortages and rising prices from abroad. In 1983, Vermont regulators began requiring utilities to buy a portion of their power from in-state-based renewable energy sources. At the time, traditional energy prices were projected to be much higher, so the prices from these alternative power plants — at anywhere between 9.6 cents and 17.5 cents a kilowatt/hour — seemed like a good deal.

Power Surge

The power prices of selected Vermont independent power plants

Nantana Mill	17.5
Comtu Falls	16.9
Newbury Hydro	14.7
Winooski One	13.0
Martinsville Hydro	12.0
Woodside Hydro	12.0
Dodge Falls	11.9
Killington Hydro	11.7
Barnet Hydro	11.5
Ryegate	10.5
New England average	3.5

Note: prices in cents per kilowatt/hour

Sources: Central Vermont Public Service, industry data

But as deregulation has swept the industry nationally, and new technologies made electricity from, say, natural gas cheaper to produce, the energy from the small Vermont plants became an expensive lesson in environmental altruism.

For example, Vermont utilities separately buy about 38% of their power supply from **Hydro-Quebec**, which at around 6.5 cents a kilowatt/hour is considerably cheaper than the electricity from the independent producers. Officials say that nationally the average wholesale price for electricity is 3.5 cents.

Complicating the situation is that unlike states like Massachusetts and Rhode Island — which have deregulated the electric industry and ordered the break-up of the old monopolies — Vermont has pressured its utilities to find ways to cut costs and restructure on their own. Utilities say they have no choice but to restructure, since they're locked into long-term contracts for power at such high prices that they face the prospect of bankruptcy.

By far, the biggest controversy for Vermont utilities is their contract with Hydro-Quebec, which runs to 2020. The utilities say that at current prices, power from Hydro-Quebec will cost Vermont $450 million more than energy at prevailing market rates. And so they're involved in a nasty fight with the Canadian power company to get out of the contract. Separately, they're selling off interests in the Vermont Yankee nuclear plant. (That sale still needs approval from state and federal regulators.)

Meantime, efforts are again under way to try to resolve the issues regarding the Vepp contracts, which generate about 74 megawatts of electricity and supply about 6% of the state's power.

The utilities and independent power producers tried to renegotiate the contracts last summer; the power producers offered to refinance their contracts in such a way that Vermont consumers would save "tens of millions" of dollars off electricity bills, says John Warshow, a partner in three hydro projects.

But the utilities say the power companies' offer was insufficient, and in August they abruptly broke off talks, and instead petitioned state regulators to consider various mechanisms to ease the burden of the contracts.

Mr. Spencer of Vepp hopes that the financial proposals Prudential is expected to develop over the next few weeks will serve as a catalyst to restart the stalled negotiations.

The ultimate goal, officials say, is a net reduction in electricity prices for Vermont consumers.

"This deal will only go forward if we

(over please)

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were to lower rates for the retail customer, while meeting the contractual obligations with the independent "producers," says Joseph Fichera, a managing director and head of Prudential's power group. "We think we can show savings."

Though still saving some strong words for each other, both utilities and the power producers cautiously welcomed the attempt by Vepp to forge a middle ground.

"As soon as they have something concrete to discuss with us," says Mr. Warshow, "I am open" to considering it, so long as it "does not adversely impact the producers and is of benefit to the rate payers." The power producers say it was they, not the utilities, who have kept the settlement process alive by pushing to have Prudential hired and a proposed financial package developed.

Meanwhile, says Robert Rogan, a vice president of Central Vermont Public Service Corp. in Rutland, who serves as a spokesman for the state's utilities in restructuring issues: "We welcome any progress. The true test will be when the negotiators come back to the table."

A settlement would need the approval of Vermont regulators, who are concerned about the level of animosity between the utilities and power producers.

Richard Sedano, commissioner of the Vermont Department of Public Service, suggests independent power producers would be wise to accept a less-than-ideal settlement. He says the high price of their electricity makes them a political target, either for regulators who are trying to lower prices in Vermont, or for state legislators who have so far held off mandating deregulation of the industry.

"A safe harbor is a nice thing to have in these times," says Mr. Sedano, "even if it costs you a little."

Exhibit O

PROSPECTUS SUPPLEMENT TO PROSPECTUS DATED APRIL 20, 2001

$525,000,000 RATE REDUCTION BONDS, SERIES 2001-1

PSNH FUNDING LLC

Issuer

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

Seller and Servicer

Rate	Interest	Initial Principal Amount	Price (%)	Price ($)	Underwriting Discounts and Commissions (%)	Proceeds to Issuer (%)(1)(2)	Scheduled Maturity Date	Final Maturity Date
Class A-1	4.57%	$ 75,211,483	99.97979%	$ 75,196,284	0.207573%	99.77222%	5/1/2003	5/1/2005
Class A-2	5.73%	$214,649,395	99.93578%	$214,511,547	0.375000%	99.56078%	11/1/2008	11/1/2010
Class A-3	6.48%	$235,139,122	99.96116%	$235,047,798	0.500000%	99.46116%	5/1/2013	5/1/2015

.....

USE OF PROCEEDS

The issuer will use the net proceeds from the sale of the bonds to purchase the RRB property from the seller and to pay the costs of issuing the bonds, including the initial funding of the interest reserve subaccount. The seller may apply the net proceeds from the sale of the RRB property in accordance with the finance order to reduce its capitalization and to buy down purchased power obligations.

Filed pursuant to Rule 424(b)(2)

Registration No. 333-76040

PROSPECTUS SUPPLEMENT
To Prospectus Dated January 16, 2002

$50,000,000 Rate Reduction Bonds, Series 2002-1

PSNH Funding LLC 2
Issuer

Public Service Company of New Hampshire
Seller and Servicer

Interest Rate	Initial Principal Amount	Price (%)	Price ($)	Underwriting Discounts and Commissions(%)	Proceeds to Issuer (%)(1)(2)	Scheduled Maturity Date	Final Maturity Date
4.58%	$50,000,000	99.972162%	$49,986,081	0.407%	99.565162%	February 1, 2008	February 1, 2010

(1) Before payment of fees and expenses.
(2) The total price to the public is $49,986,081 and the total amount of the underwriting discounts, commissions and other fees is $353,500. The total amount of proceeds before deduction of expenses (estimated to be $1,480,000) is $49,632,581.

…….

USE OF PROCEEDS

The issuer will use the net proceeds from the sale of the bonds to purchase the RRB property from the seller and to pay the costs of issuing the bonds, including the initial funding of the interest reserve subaccount. The seller may apply the net proceeds from the sale of the RRB property in accordance with the finance order to buy down purchased power obligations.

Exhibit P

Potential savings from PPA buydown

Buydown Assumptions

	Escalation rates	Prices Year 1	Year 2	
Market Price- $/MWH	1.80%	50	50.9	.....
Old Contract Price- $/MWH	0.90%	185	186.7	.....
		Sales		
Annual Sales (GWH)		2,000	2,000	.....

Cost of Capital

Securitization (20 yr. final maturity)	3.91%
PPA Investor	6.50%
Ratepayer	7.69%

PPA owner cost of capital (hypothetical):

Source of Capital	Capital Structure	Annualized Cost	Wtd. Avg. Cost of Capital (WACC)	Pre-Tax Cost of Capital
Common Equity	5.00%	25.00%	1.25%	1.74%
Long-Term Debt	95.00%	5.53%	5.25%	5.25%
Total Capitalization	100.00%		6.50%	6.99%

Buydown Potential Savings

($ millions)

	Year 1	Year 2		Nominal Total	NPV @7.69%	NPV @ 6.5%
Old PPA Rev. Req.	**370.0**	**373.3**	**....**	**5,914**	**3,398**	**3,669**
Market PPA	100.0	101.8	....	1,705	968	1,047
Mkt PPA +10.%	110.0	112.0	....	1,875	1,064	**1,151**
20 Year Levelized bond pmt	187.6	187.6	....	3,751	1,885	2,067
Total New Rev Req.	**297.6**	**299.5**	**....**	**5,626**	**2,949**	**3,218**
Savings				287	449	
Savings as % of principal				11%	**17%**	

2,517	Buydown Cost
51	2% NPV upfront & ongoing costs
2,569	Principal Amount

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NPV savings from PPA buydown may be achieved by stretching out securitization

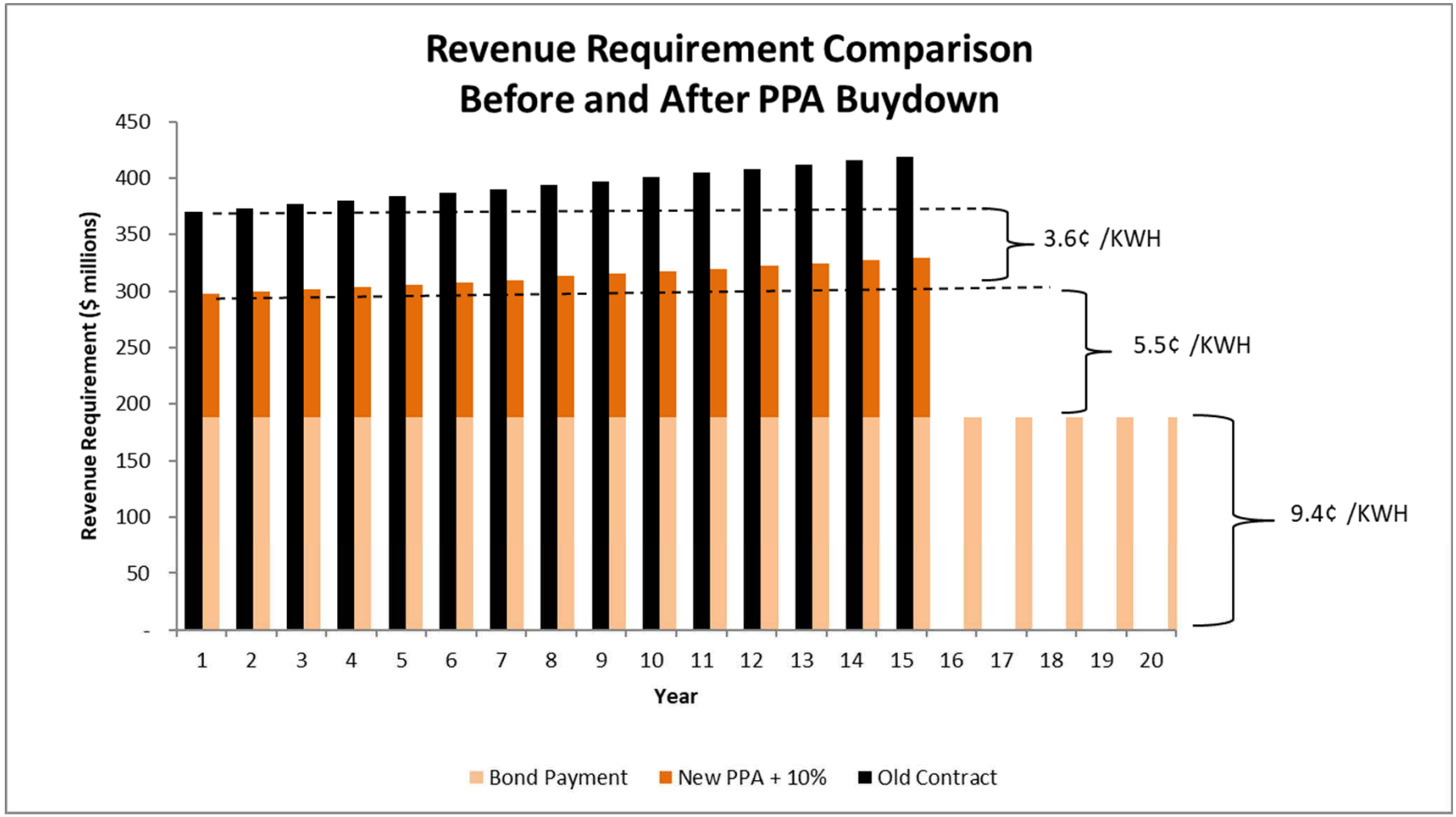

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Exhibit Q

Source of Data Used* in Financial Model Of PG&E and SCE Securitization of UOG

PG&E Inputs

Input	Source
Capital structure	PG&E Advice Letter 3887
Cost of capital	PG&E Advice Letter 3887
2017 Y/E Rate base amounts for Diablo Canyon, hydro, and fossil generation	PG&E's response to CCSF Data Request #2, questions 5-7
2017 Y/E Rate base for solar generation	PG&E's 2017 GRC workpapers for Exhibit PG&E-10, page 14-2
Remaining useful lives	PG&E's 2017 GRC workpapers (same as above), Table 11-1, beginning on page 11-3
Franchise fee factor	PG&E Advice Letter 3894

SCE Inputs

Input	Source
Capital structure	SCE Advice Letter 3665
Cost of capital	SCE Advice Letter 3665
2017 Y/E Rate base amounts and remaining useful lives	SCE workpapers in A. 16-09-001, SCE workpapers for SCE 9 Volume 2, Chapters I and II, pages 133-146

*Provided to Saber Partners, LLC by California Community Choice Association