BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
OKLAHOMA GAS AND ELECTRIC COMPANY	)	
FOR APPROVAL OF A GENERAL CHANGE IN	)	**DOCKET NO. 16-052-U**
RATES, CHARGES, AND TARIFFS	)	

DIRECT EXHIBITS OF

William Perea Marcus

on behalf of

THE OFFICE OF ARKANSAS ATTORNEY GENERAL LESLIE RUTLEDGE

January 31, 2017

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WM-1 Qualifications of William Perea Marcus

William Perea Marcus
Principal Economist
JBS Energy, Inc.

William B. Marcus has 38 years of experience in analyzing electric and gas utilities.

Mr. Marcus graduated from Harvard College with an A.B. magna cum laude in economics in 1974 and was elected to Phi Beta Kappa. In 1975, he received an M.A. in economics from the University of Toronto.

In July, 1984, Mr. Marcus became Principal Economist for JBS Energy, Inc. In this position, he is the company's lead economist for utility issues.

Mr. Marcus is the co-author of a book on electric restructuring prepared for the National Association of Regulatory Utility Commissioners. He wrote a major report on Performance Based Ratemaking for the Energy Foundation.

Mr. Marcus has prepared testimony and formal comments submitted to the Federal Energy Regulatory Commission, the National Energy Board of Canada, the Bonneville Power Administration, the U.S. Bureau of Indian Affairs, U.S. District Court in San Diego, Nevada County Municipal Court; committees of the Nevada, Ontario and California legislatures and the Los Angeles City Council; the California Energy Commission (CEC), the Sacramento Municipal Utility District (SMUD), the Transmission Agency of Northern California, the State of Nevada's Colorado River Commission, a hearing panel of the Alberta Beverage Container Management Board; two arbitration cases, environmental boards in Ontario, Manitoba, and Nova Scotia; and regulatory commissions in Alberta, Arizona, Arkansas, British Columbia, California, Colorado, Connecticut, District of Columbia, Hawaii, Iowa, Manitoba, Maryland, Massachusetts, Nebraska, Nevada, New Jersey, New Mexico, North Carolina, Northwest Territories, Nova Scotia, Ohio, Oklahoma, Ontario, Oregon, South Carolina, Texas, Utah, Vermont, Virginia, Washington, Wisconsin, and Yukon. He testified on issues including utility restructuring, stranded costs, Performance-Based Ratemaking, resource planning, load forecasts, need for powerplants and transmission lines, environmental effects of electricity production, evaluation of conservation potential and programs, utility affiliate transactions, mergers, utility revenue requirements, avoided cost, and electric and gas cost of service and rate design.

From September 1975 through June 1978, Mr. Marcus was a case writer at the John F. Kennedy School of Government at Harvard University. From July, 1978 through April, 1982, Mr. Marcus was an economist at the CEC, first in the energy development division and later as a senior economist in the CEC's Executive Office. He prepared testimony on purchased power pricing and economic studies of transmission projects, renewable resources, and conservation programs, and managed interventions in utility rate cases.

From April, 1982, through June, 1984, he was principal economist at California Hydro Systems, Inc., an alternative energy consulting and development company. He prepared financial analyses of projects, negotiated utility contracts, and provided consulting services on utility economics.

Arkansas Testimony

Arkansas Electric Cooperative Corporation ("AECC") Dockets 12-012-U, 04-141-U

Arkansas Oklahoma Gas Corporation ("AOG") Dockets 16-081-U, 13-078-U, 07-026-U, 05-006-U and 02-024-U

CenterPoint Energy Arkansas and predecessors ("CenterPoint") General Rate Case Dockets 06-161-U, 04-121-U and 01-243-U and Docket 10-108-U.

The Empire District Electric Company ("EDE"), General Rate Case Dockets 13-111-U, 10-052-U and 04-100-U and Docket 15-010-U.

Entergy Arkansas, Inc. ("EAI") General Rate Case Dockets 15-015-U, 13-028-U, 09-084-U, and 06-101-U and other Dockets 15-014-U, 14-118-U, 12-069-U, 12-056-U, 12-038-U, 11-069-U, 10-011-U. 08-149-U, 07-129-U, 06-152-U, 01-041-U and 01-184-U

Oklahoma Gas and Electric ("OG&E") General Rate Case Dockets 10-067-U, 08-103-U and 06-070-U and Docket 15-034-U.

Source Gas Arkansas ("SGA") and Arkansas Western Gas Company ("AWG") Dockets 15-078-U, 15-011-U, 13-079-U, 06-124-U, 04-176-U, 02-179-U, and 02-227-U

Southwestern Electric Power Company ("SWEPCO"): General Rate Case Dockets No. 09-008-U and 98-339-U and Dockets 15-021-U and 11-050-U.

Conservation-related dockets 08-137-U, 07-077-TF, 07-078-TF, 07-081-TF and 07-085-TF, and 05-111-P

Restructuring Investigation Docket No. 00-190-U (September, 2000 and September, 2001 phases)

Approximately 20 rate unbundling cases for co-ops and investor-owned utilities, most of which were settled.

WM-2 “The Fall in Interest Rates, Low Pressure”, The Economist, Sept. 24, 2016.

The Economist

The fall in interest rates

Low pressure

Interest rates are persistently low. In our first article we ask who or what is to blame. In the second we look at one outcome: a looming pensions crisis

Sep 24th 2016

THE story of rich-world central banks and their protracted entanglement with near-zero interest rates was given another twist this week. One of their number gamely announced it still hoped for a more distant relationship, even if it couldn't bring itself to turn its back on them yet. Another renewed its vows to stick with them.

On September 21st the Federal Reserve kept its target for overnight interest rates at 0.25-0.5% but indicated that, after raising the target for the first time in a decade last year, it hoped to raise it for a second time soon—possibly in December, after America's presidential elections. Its rate-setting committee said the case for an increase had "strengthened" since its meeting in June, but it decided to wait for more convincing evidence. Earlier that day, the Bank of Japan (BoJ) said it was staying with its target of raising inflation to 2%. Indeed it went further. The bank said it would continue to buy bonds at a rate of around ¥80 trillion ($800 billion) a year, until inflation gets above 2% and stays there for a while. To help meet this "inflation-overshooting commitment", the bank said ten-year-bond yields would remain at around zero.

The BoJ also stuck with another unorthodox policy. Along with the European Central Bank (ECB) and a handful of smaller central banks, it charges commercial banks a small fee (a negative interest rate) to hold cash reserves. This through-the-looking-glass practice has spread to capital markets. Sanofi, a French drugmaker, and Henkel, a German manufacturer of detergent, both this month issued bonds denominated in euros with a negative yield. Investors will make a guaranteed cash loss if they hold the bonds to maturity. Earlier Germany became the first euro-zone government to issue a bond that promises to pay back to investors less than the sum it raised from them. A large proportion of all rich-country sovereign bonds now have negative yields.

You can't always get what you want

The debt-laden are delighted with the persistence of a low-rate world. It costs much less to service their obligations. But savers are increasingly grumpy. Economists are simply baffled. In the 1980s and 1990s, the high real cost of borrowing (ie, after adjusting for inflation) was the puzzle. Today's interest-rate mystery is more troubling and there is division over the reasons for it.

One side says it is simply the consequence of the policies pursued by the rich world's central banks. The Fed, ECB, BoJ and Bank of England have kept overnight interest rates close to zero for much of the past decade. In addition, they have purchased vast quantities of government bonds with the express aim of driving down long-term interest rates.

It is hardly a mystery, on this view: central banks have rigged the money markets. They have been aided in this task by new regulations, written in the wake of the global financial crisis, that require banks and insurance companies to keep more of their assets in safe and liquid instruments, such as government bonds. That is helpful, say sceptics, to rich-world governments with large debts which need to keep interest costs low. But it is punishing the thrifty and those who rely on bonds for their income.

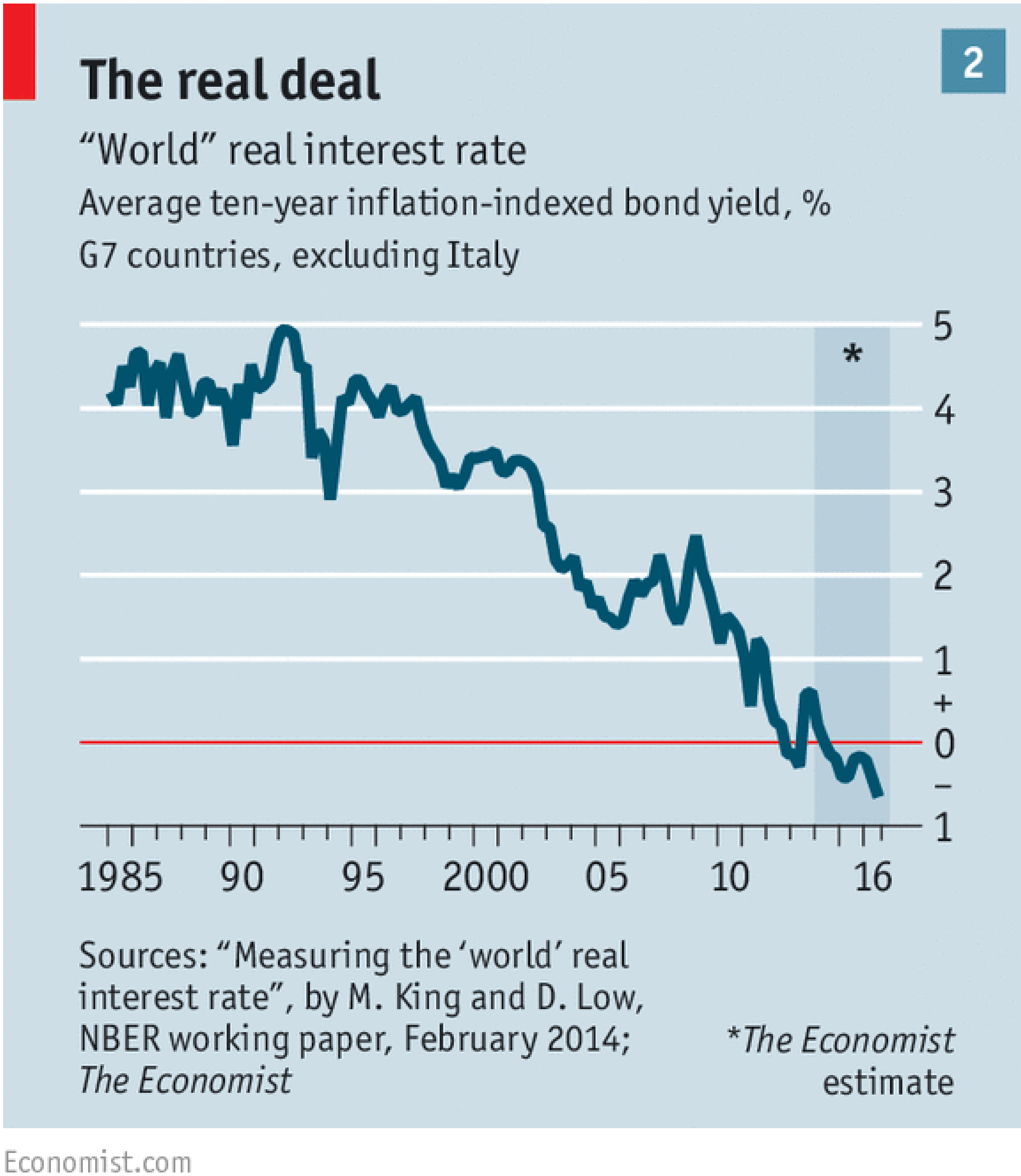
On the other side of the divide are those who argue that central banks are merely responding to underlying forces. In this view the real interest rate is decided by the balance of supply and demand for the pool of global savings. The fall in interest rates since the 1980s reflects a shift in this balance: the supply of savings has increased as demand for it has crashed. Short-term nominal interest rates are stuck at zero, or a little below, because, in the absence of inflation, real interest rates cannot fall far enough to clear the world market for savings. Far from rigging things, central banks are struggling to find ways to help the market work so that the economy can function normally. Which side is right?

The present combination of low nominal and real interest rates is unprecedented. David Miles, a member of the Bank of England's monetary-policy committee, has worked out that the average short-term interest rate set by the bank since 1694, when it was founded, is around 4.8% (see chart 1). Indeed, for over a century after 1719, the bank kept its main interest rate at exactly 5%. But it is the real (ie, inflation-adjusted) rate that keeps the demand and supply of savings in balance.

If savers believe inflation will rise, they will demand a higher nominal interest rate to compensate for the expected loss of spending power. Borrowers, by contrast, will be keen to take on debt if they believe they can pay it back in devalued currency. Mr Miles calculates that inflation in Britain was around 2% in the three-and-a-bit centuries after 1694. That means the real interest rate was around 2.8%, assuming that inflation lived up (or down) to expectations.

That is a bold assumption. Thankfully, these days it is possible to work out long-term interest rates in real terms from the yields on inflation-protected bonds. Mervyn King, a former governor of the Bank of England, and David Low of New York University have estimated a real interest rate for G7 countries, excluding Italy, using such data going back to the mid-1980s. It shows a steady decline over the past 20 years. This era of falling real rates might usefully be split into two distinct periods: before and after the financial crisis of 2008-09. In the first period, real rates fell from above 4% to around 2%. Since the start of 2008, real long-term rates have fallen further, and faster, to around -0.5% (see chart 2).

Down, down, deeper and down



By the 2000s it was already becoming clear that something was afoot. In 2004 the Fed began to increase short-term rates. That would normally be followed by a rise in long-term bond yields. Instead, bond yields fell, not only in America but across the world. That might make sense if bond investors expected durably lower inflation. In fact most of the fall was down to a decline in real interest rates; expectations of inflation had hardly changed. This was a "conundrum", said Alan Greenspan, then chairman of the central bank. Ben Bernanke, a Fed governor who later took over from Mr Greenspan in the top job, identified a worldwide "saving glut" as the culprit for the decline in real rates.

This ongoing glut in savings is due to two factors in particular, according to last year's *Geneva Report*, an annual study from the International Centre for Monetary and Banking Studies and the Centre for Economic Policy Research. The first is changing demography, mostly in the rich world but also in some emerging markets. Populations are ageing. At the same time, the average working life has not changed much. So more money has to be squirrelled away to pay for a longer retirement (see article (http://www.economist.com/news/briefing/21707560-it-costs-lot-more-fund-modern-retirement-employers-workers-and-governments-are-not)). A lot of that saving takes place during the best-paid years in middle age. The size of the world population (excluding China) of peak-earning age (40-64) was rising over the past two decades relative to those of retirement age. As a consequence of this, saving increased and real interest rates have steadily fallen.

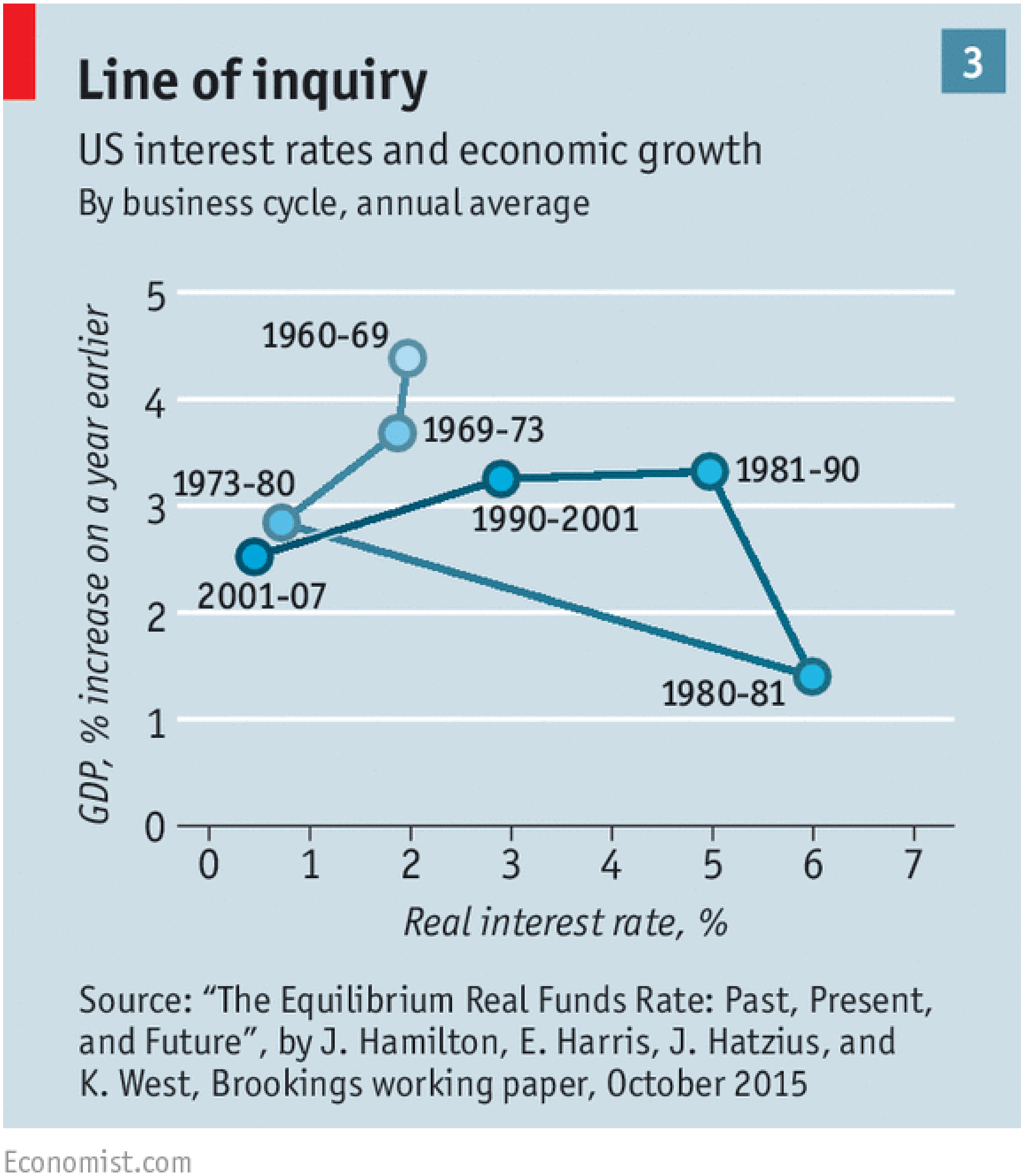
A second, related, factor is the integration of China into the world economy. "A billion people with a 40% savings rate; that brings a lot more supply to the table," says Randall Kroszner of the University of Chicago's Booth business school, one of the authors of the *Geneva Report* and a former Fed governor. Even though a massive slug of its GDP goes on investment, China still has savings left over to send abroad. That is why Mr Bernanke also blamed the saving glut for America's current-account deficit: if China saved a lot, every one else must save less. Explanations for its unusually high savings pile are also in part demographic. In the absence of a broad-based pension system, the family is the main social safety net. But family networks are a weak form of insurance because of China's one-child policy. So working people have had to save furiously.

Ageing is not the only long-run influence that has tilted the savings-investment scales. By skewing income to the high-saving rich, an increase in income inequality within countries has added to the saving glut. A fall in the relative price of capital goods means fewer savings are needed for a given level of investment. Both trends predate the fall in real interest rates, however, which suggests they did not play as significant a role as demography or China.

Others reckon the drop in real interest rates reflects a shift down in underlying trend growth, both before and since the crisis. For Larry Summers of Harvard University, this "secular stagnation" is a consequence of a chronic shortfall in demand. Robert Gordon of Northwestern University reckons the trouble lies with the economy's supply-side. The new digital and robot technologies cannot match the surge of productivity from past inventions such as electricity, the motor car, petrochemicals and indoor plumbing, he argues.

In fact, the historical relationship between real interest rates and economic growth is weak, according to a recent study by James Hamilton of the University of California at San Diego, and his co-authors. They find that the correlation between GDP growth and the real short-term interest rate across the seven most recent economic cycles in America was only mildly positive—and then only if the brief recovery before the second dip of the early 1980s "double-dip" recession is excluded. Include it and the correlation is negative (see chart 3).

In the period since the financial crisis, real rates have fallen even faster. The same secular forces have been at work, plus some new ones—notably "deleveraging". Though middle-aged households were saving hard in the run-up to the crisis, many younger ones were piling on debts to buy overpriced homes. When house prices and incomes started to fall, those mortgage debts loomed much larger and so they saved more.



A related reason for more saving is fear. The severity of the Great Recession belied the relative economic stability that preceded it. Mr Miles calculates that the probability of a decline in British output as sharp as that in 2009 was 0.0004% (or one in 240,000 years) based on the volatility of GDP growth between 1949 and 2006. As people become aware of the possibility of such rare events, their caution could cut the risk-free real interest rate by 1.5-2 percentage points on plausible assumptions.

Low rider

Ageing populations, debt hangovers, fear and secular stagnation: if low real rates are a crime, there is no shortage of suspects. Some look guiltier than others. But for many the principal villains are central banks. They have pushed short-term interest rates to zero and kept them there. They have also spent huge sums of electronic cash buying long-term bonds.

Their defenders say central banks are typically reacting to economic trends, not shaping them. A lodestar for central-bank policy is the idea of the "neutral" real interest rate, a close cousin of the real rate determined in the market for long-term savings. This is the short-term real interest rate that keeps inflation stable when the economy is running at full capacity, with no idle workers, factories or offices.

When inflation is low and the economy weak, as has been the case since 2008, central banks should aim to set nominal interest rates below the sum of the neutral real rate and the inflation target. The higher propensity to save means the neutral real rate is lower—probably much lower—than in the past. Since short-term nominal interest rates cannot be pushed much below zero, central banks have resorted to bond purchases to depress long-term borrowing rates and push investors into riskier assets, to give a fillip to the economy. And if interest rates and bond yields were really too low, it should lead to overheating and rising inflation. There are no signs of this.

Even so, something is amiss in bond markets when many rich-country government bonds have a negative yield and firms can sell debt by promising to pay back less than they borrow. This might be fitting if economies were in a deflationary spiral. But GDP growth is not collapsing. Inflation is low, but is in general moving sideways, not downwards. Big budget deficits in many rich countries mean the supply of new government debt is hardly drying up.

Free falling

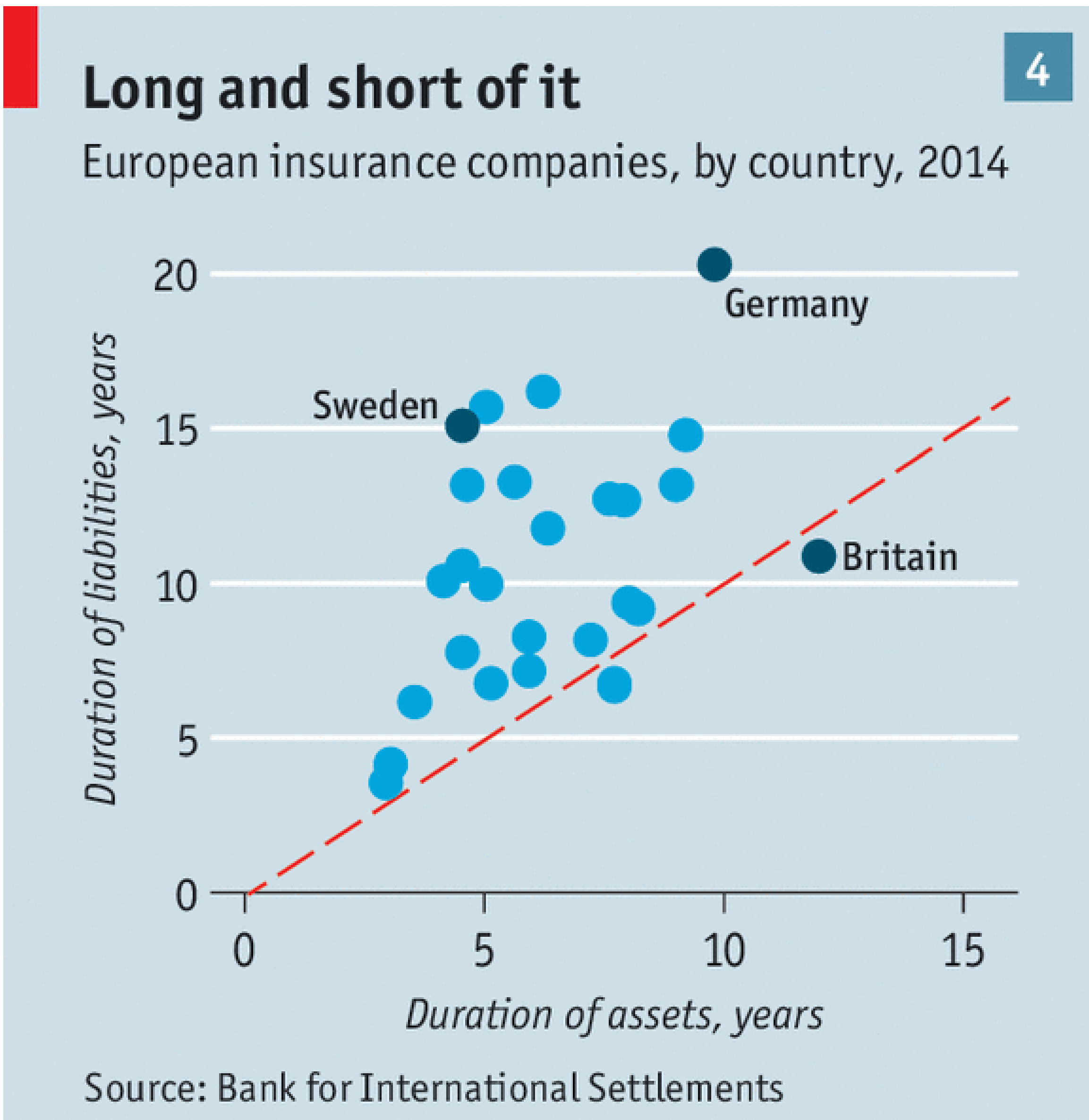
The promise of continuous central-bank action has affected bond markets. Calling the top of the bull market in bonds has for years been a fool's errand. Still, it is becoming ever harder to make sense of today's bond prices. The idea that there is, or ought to be, a link between the amount of public borrowing and interest rates has become almost quaint. The yields on the bonds of high-debt, low-growth Italy are lower than the yields on the bonds of low-debt, high-growth Australia. It is difficult to explain Italy's yields without reference to the ECB's bond-buying programme.

What is more, the impact of ever-lower rates may be starting to pall. In principle, cuts in interest rates boost the economy by nudging consumers and companies to spend now and save later. But there are forces working in the other direction, too. If savers have a target level of savings in mind to fund retirement, low or negative interest rates slow down the progress in reaching their goals. For such people, low rates mean less spending now, not more. Similarly, a low risk-free rate of interest drives up the present value of future pension obligations for employers who have promised their workers a defined benefit on their retirement.

Such firms may find that the profits they are obliged to set aside to fill the growing holes in their pension funds leave them little left over for investment. They could of course borrow but the magnitude of some pension deficits means that lenders might view such firms as a poor credit risk. It is likely that in the tug-of-war between the parts of the economy that are induced to spend now and save later by low rates, and those that are spurred to do the opposite, the former is stronger. But with risk-free interest rates at such low levels for such a long time, the fight is probably far less one-sided than in normal times.

Indeed attempts to guard against the impact of low rates may perversely become a cause of even lower rates. Accounting rules and solvency regulations are a spur to bond-buying even at super-low interest rates. To understand why, consider the business of life-assurance companies. They pledge to pay a stream of cash to policyholders, often for decades. This promise can be likened to issuing a bond. Insurance firms need to back up these promises. To do so they buy safe assets, such as government bonds.

The trouble is that the maturities on these bonds are shorter than the promises the insurers have made. In the jargon, there is a "duration mismatch". When bond yields fall, say because of central-bank purchases, the cost of the promises made by insurance companies goes up. The prices of their assets go up as well, but the liability side of the scales is generally weightier (see chart 4). And it gets heavier as interest rates fall. That creates a perverse effect. As bond prices rise (and yields fall), it increases the thirst for bonds. Low rates beget low rates.



Economist.com

This dynamic might materially affect bond yields if the weight of forced buyers were large enough. In 2014-15 yields on ten-year German bonds fell from around 2% to a low of close to zero, in response to expectations of quantitative easing by the ECB. A study by Dietrich

Domanski, Hyun Song Shin and Vladyslav Sushko of the Bank of International Settlements finds that the fall in yields induced German insurers to buy more bonds. Insurers started 2014 with €60 billion-worth of government bonds but ended it holding €80 billion-worth.

Such a rapid rate of government-bond purchases was out of keeping with previous years. Long-maturity bonds were particularly sought after. This episode lends support to the idea that demand for bonds increases even as their price rises, where there is a mismatch of assets and liabilities. Those who worry that central-bank actions have led to distortions in capital markets seem to have a point.

If a growing bulge of middle-aged workers is behind the secular decline in real interest rates, then the downward pressure ought to attenuate as those workers move into retirement. Japan is further along this road than other rich countries. Yet its long-term real interest rates are firmly negative. That owes at least something to the open-ended quantitative easing by the Bank of Japan. A concern is that as more people retire, and save less, there will be fewer buyers for government bonds, of which less than 10% are held outside Japan. Another of the *Geneva Report*'s authors, Takatoshi Ito of Columbia University, reckons there will be a sharp rise in Japanese bond yields within the next decade. There may be political pressure on the Bank of Japan to keep buying bonds to prevent this.

Slip sliding away

A chorus of economists will vigorously dispute the idea that central banks have lost their power to pep up the economy. In principle, they could print money to buy any number of assets, including stocks (Japan's central bank is already a big buyer of equities). They could test the lower bounds of standard monetary policy by edging interest rates further into negative territory. And they could raise their inflation targets so that an interest rate of zero translates into a lower real interest rate.

But a lesson from the 1980s is that inflation expectations can take a long time to adjust fully to a new target. Each new round of central-bank action seems to bring less stimulus and more side-effects. The concept of using fiscal policy to fine-tune the economy went out of style around the time when economists were trying to work out why real interest rates were unusually high. Perhaps it is time to dust that idea down.

This article appeared in the Briefing section of the print edition

WM-3 Graham, John R. and Harvey, Campbell R. “The Equity Risk Premium in 2016”, Available: http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2611793

The Equity Risk Premium in 2016

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ABSTRACT

We analyze the history of the equity risk premium from surveys of U.S. Chief Financial Officers (CFOs) conducted every quarter from June 2000 to June 2016. The risk premium is the expected 10-year S&P 500 return relative to a 10-year U.S. Treasury bond yield. The average risk premium in 2016, 4.02%, is slightly higher than the average observed over the past 16 years. We also provide results on the risk premium disagreement among respondents as well as asymmetry or skewness of risk premium estimates. We also link our risk premium results to survey-based measures of the weighted average cost of capital and investment hurdle rates. The hurdle rates are significantly higher than the cost of capital implied by the market risk premium estimates.

JEL Classification: *G11, G31, G12, G14*

Keywords: *Cost of capital, financial crisis, equity premium, WACC, hurdle rate, long-term market returns, stock return forecasts, long-term equity returns, expected excess returns, disagreement, individual uncertainty, skewness, asymmetry, survey methods, TIPs, VIX, credit spreads*

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Introduction

We analyze the results of the most recent survey of Chief Financial Officers (CFOs) conducted by Duke University and *CFO* Magazine. The survey closed on June 2, 2016 and measures expectations beginning in the second quarter of 2016. In particular, we poll CFOs about their long-term expected return on the S&P 500. Given the current U.S. 10-year Treasury bond yield, we provide estimates of the equity risk premium and show how the premium changes through time. We also provide information on the disagreement over the risk premium as well as average confidence intervals. Finally, we link the equity risk premium to measures used to evaluate firm's investments: the weighted average cost of capital (WACC) and the investment hurdle rate.

1. Method

2.1 Design

The quarterly survey of CFOs was initiated in the third quarter of 1996.[1] Every quarter, Duke University polls financial officers with a short survey on important topical issues (Graham and Harvey, 2009). The usual response rate for the quarterly survey is 5%-8%. Starting in June of 2000, a question on expected stock market returns was added to the survey. Fig. 1 summarizes the results from the risk premium question. While the survey asks for both the one-year and ten-year expected returns, we focus on the ten-year expected returns herein, as a proxy for the market risk premium.

The executives have the job title of CFO, Chief Accounting Officer, Treasurer, Assistant Treasurer, Controller, Assistant Controller, or Vice President (VP), Senior VP or Executive VP of Finance. Given that the majority of survey respondents hold the CFO title, for simplicity we refer to the entire group as CFOs.

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[1] The surveys from 1996Q3-2004Q2 were partnered with a national organization of financial executives. The 2004Q3 and 2004Q4 surveys were solely Duke University surveys, which used Duke mailing lists (previous survey respondents who volunteered their email addresses) and purchased email lists. The surveys from 2005Q1 to present are partnered with *CFO magazine*. The sample includes both the Duke mailing lists and the *CFO* subscribers that meet the criteria for policy-making positions.

2.2 Delivery and response

In the early years of the survey, the surveys were faxed to executives. The delivery mechanism was changed to the Internet starting with the December 4, 2001 survey. Respondents are given four business days to fill out the survey, and then a reminder is sent allowing another four days. Usually, two-thirds of the surveys are returned within two business days.

The response rate of 5-8% could potentially lead to a non-response bias. There are six reasons why we are not overly concerned with the response rate. First, we do not manage our email list. If we deleted the email addresses that had not responded to the survey in the past 12 quarters, our response rate would be in the 15-20% range – which is a good response rate. Second, Graham and Harvey (2001) conduct a standard test for non-response biases (which involves comparing the results of those that fill out the survey early to the ones that fill it out late) and find no evidence of bias. Third, Brav, Graham, Harvey and Michaely (2005) conduct a captured sample survey at a national conference in addition to an Internet survey. The captured survey responses (to which over two-thirds participated) are qualitatively identical to those for the Internet survey (to which 8% responded), indicating that non-response bias does not significantly affect their results. Fourth, Brav et al. contrast survey responses to archival data from Compustat and find archival evidence for the universe of Compustat firms that is consistent with the responses from the survey sample. Fifth, Campello, Graham, and Harvey (2011) show that the December 2008 response sample is fairly representative of the firms included in the commonly used Compustat database. Sixth, Graham, Harvey, Popadak and Rajgopal (2016) update the non-response bias test in a survey of 1,900 CFOs and find no evidence of non-response bias.

2.3 Data integrity

In each quarter, implement a series of rules to ensure the integrity of the data. We have, on average, 355 responses each quarter. However, in recent years the average number of responses has exceeded 400. There are a total of 23,086 survey observations. There are six key pieces of data: 1) the 10-year forecast (LT); 2) lower 10% of 10-year forecast (LLT); and 3) upper 10% of the

10-year forecast (ULT). We collect the analogous information for the one-year S&P 500 forecasts too (ST). This paper focuses on the 10-year forecasts but the short-term forecasts factor into our data filters.

Our exclusion rules are the following:

1. Delete all missing forecasts, LT, ST
2. Delete all negative LT forecasts (not ST forecasts)
3. Delete all observations that failed to use percentages (forecasts<1.0 for both ST and LT)
4. Delete observations where they failed to annualize, i.e. delete if LT>30% (does not apply to ST)
5. Delete is ST>100%.
6. Delete if lower intervals inconsistent, i.e. LST>=ST or LLT>=LT.
7. Delete if upper intervals inconsistent, i.e. UST<=ST or ULT<=LT.
8. Delete if ST-LST and UST-ST both equal 1 (we call this a lazy answer)
9. Delete if LT-LLT and ULT-LT both equal 1 (again, a lazy answer)

2.4 The 2016 results

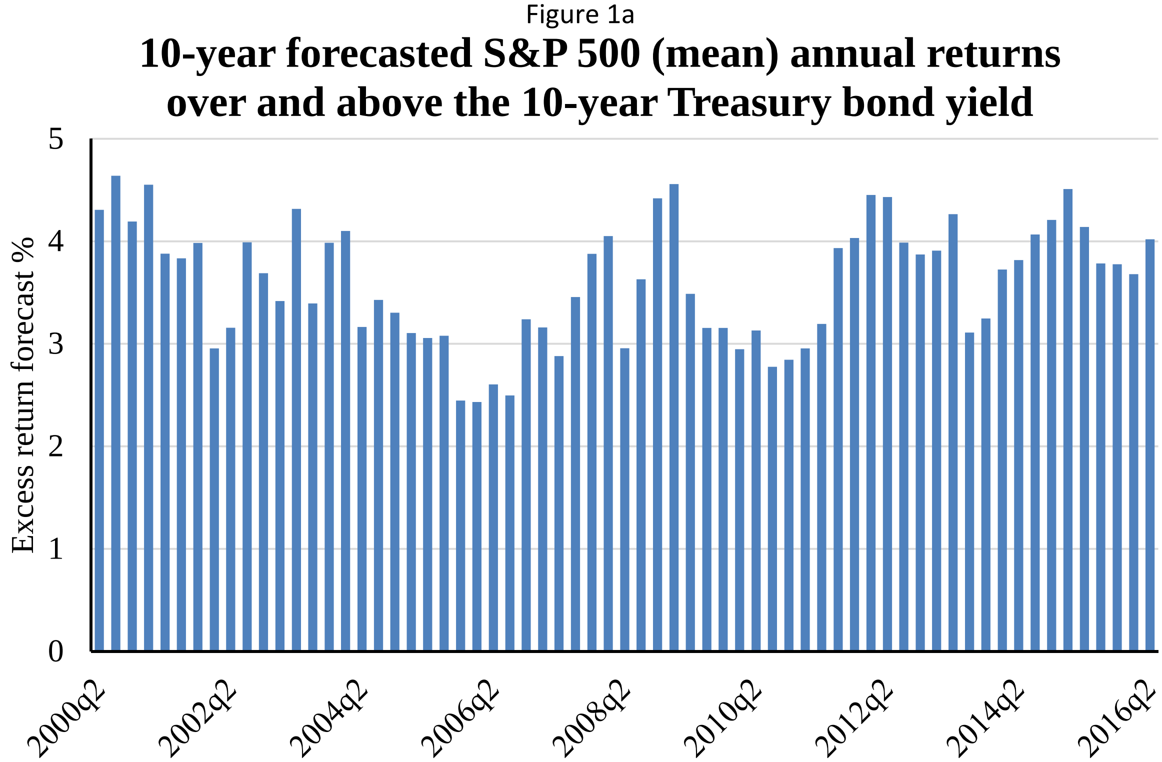
The expected market return questions are a subset of a larger set of questions in the quarterly survey of CFOs. The survey usually contains between eight and ten questions. Some of the questions are repeated every quarter and some change through time depending on economic conditions. The historical surveys can be accessed at http://www.cfosurvey.org. Appendix 1 shows the risk premium question in the most recent survey.

While the survey is anonymous, we collect demographic information on seven firm characteristics, including industry, sales revenue, number of employees, headquarters location, ownership (public or private), and proportion of foreign sales.

During the past 16 years, we have collected over 23,000 responses to the survey. Panel A of Table 1 presents the date that the survey window opened, the number of responses for each survey, the 10-year Treasury bond rate, as well as the average and median expected excess returns. There is relatively little time variation in the risk premium. This is confirmed in Fig. 1a, which displays the historical risk premiums contained in Table 1. The current premium, 4.02%, is close to the historical average. The June 2016 survey shows that the expected annual S&P 500 return is 5.83% (=4.02%+1.81%) which is below the overall average of 7.19%. The total return forecasts are presented in Fig. 1b.[2]

Panel B of Table 1 presents some summary statistics that pool all responses through the 16 year history of the survey. The overall average ten-year risk premium return is 3.58%.[3] The standard deviation of the individual responses is 2.91% (see Panel B). The standard deviation of the quarterly risk premium estimates is 0.58% (not reported in the Table).

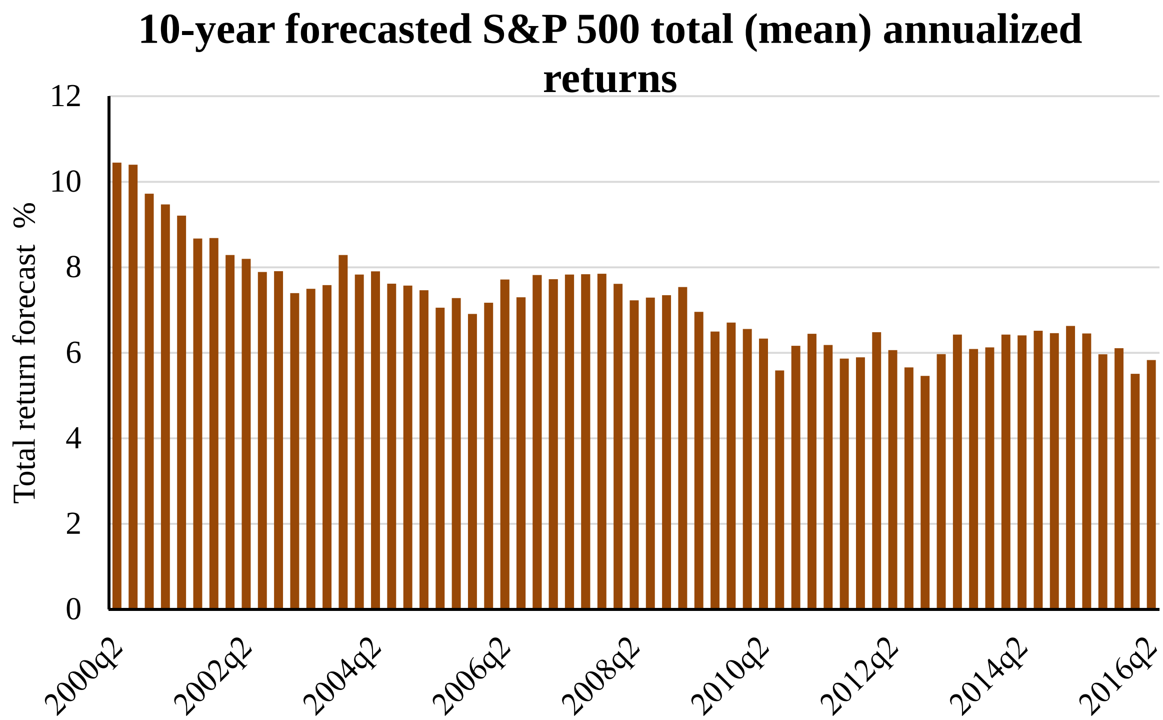
Figure 1a



[2] See, for example, Ghysels (1998), Welch (2000, 2001, 2009), Ghysels (1998), Fraser (2001), Harris and Marston (2001), Pástor and Stambaugh (2001), Fama and French (2002), Goyal and Welch (2003), Graham and Harvey (2003), Ang and Bekaert (2005), Fernandez (2004, 2006, 2009) for studies of the risk premium.

[3] Using the Ibbotson Associates data from January 1926 through July 2010, the arithmetic (geometric) average return on the S&P 500 over and above the 30-day U.S. Treasury bill is 7.75% (5.80%). Using data from April 1953-July 2010, the arithmetic (geometric) risk premium is 6.27% (5.12%). The risk premium over the 10 year bond should be reduced by 212 basis points for the arithmetic premium and 174 basis points for the geometric premium. Fama and French (2002) study the risk premium on the S&P 500 from 1872-2000 using fundamental data. They argue that the ex ante risk premia is between 2.55% and 4.32% for 1951-2000 period. Ibbotson and Chen (2001) estimate a long-term risk premium between 4 and 6%. Also see Siegel (1999), Asness (2000), Heaton and Lucas (2000) and Jagannathan, McGratten and Scherbina (2001). A recent treatment is Sharpe and Suarez (2013).

Figure 1b



The cross-sectional standard deviation across the individual CFO forecasts in a quarter is a measure of the disagreement or dispersion of the participants in each survey. Dispersion sharply increased during the global financial crisis. The average disagreement in 2005 was 2.39%. Disagreement increased in 2006 to 2.64%. As the crisis began in 2007, disagreement increased to 2.98 by March 2008. The peak disagreement was recorded in February 2009 (4.13%). The most recent observation is 3.24%.

We also report information on the average of the CFOs' assessments of the one in ten chance that the market will exceed or fall below a certain level. In the most recent survey, the worst case total return is +0.39% which is lower than the historic average of 1.52%. The best-case return is 9.71% which is also slightly lower than the average of 10.97%.

With information on the 10% tails, we construct a probability distribution for each respondent. We use Davidson and Cooper's (1976) method to recover each respondent's probability distribution:

$$\text{Variance} = ([x(0.90)\text{-}x(0.10)]/2.65)^2$$

where *x*(0.90) and *x*(0.10) represent the 90th and 10th percentiles of the respondent's distribution, ULT and LLT. Keefer and Bodily (1983) show that this simple approximation is the preferred method of estimating the variance of a probability distribution of random variables, given information about the 10th and 90th percentiles. Like disagreement, the average of individual volatilities peaked in February 2009 at 4.29%. The current level, 3.52%, is very close to the overall average.

There is also a natural measure of asymmetry in each respondent's response. We look at the difference between each individual's 90% tail and the mean forecast and the mean minus the 10% tail. Hence, if the respondent's forecast of the excess return is 6% and the tails are -8% and +11%, then the distribution is negatively skewed with a value of -9% (=5%-14%). As with the usual measure of skewness, we cube this quantity and standardize by dividing by the cube of the individual standard deviation. In every quarter's survey, there is on average negative skewness in the individual forecasts. The average asymmetry -0.63 which is slightly lower than the average of -0.47.

Table 1

Summary statistics based on the responses from the 65 CFO Outlook Surveys from June 2000 to June 2016 (Maximums in red, minimums in green)

A. By quarter

#	Survey date	Survey quarter	Number of survey responses	10-year bond yield	Total market return forecast	Average risk premium	Median risk premium	Disagreement (standard deviation of risk premium estimates)	Average of individual standard deviations	Average of individuals' worst 10% market return scenario	Average of individuals' best 10% market return scenario	Skewness of risk premium estimates	Average of individuals' asymmetry	% who forecast negative excess return
1	6/6/2000	2000Q2	209	**6.14**	**10.45**	4.31	3.86	3.22				0.95		9.09
2	9/7/2000	2000Q3	188	5.76	10.40	**4.64**	4.24	3.03				0.83		4.79
3	12/4/2000	2000Q4	243	5.53	9.72	4.19	4.47	2.52				0.53		4.12
4	3/12/2001	2001Q1	140	4.92	9.47	4.55	4.58	2.91				0.78		3.57
5	6/7/2001	2001Q2	208	5.33	9.21	3.88	3.67	2.64				0.58		5.77
6	9/10/2001	2001Q3	199	4.84	8.67	3.83	3.16	2.53				**0.13**		3.52
7	12/4/2001	2001Q4	279	4.70	8.68	3.98	3.30	2.43				0.61		2.15
8	3/11/2002	2002Q1	233	5.33	8.29	2.96	2.67	2.43	3.28	**3.68**	12.42	1.06	-0.28	11.16
9	6/4/2002	2002Q2	316	5.04	8.20	3.16	2.96	2.61	3.50	3.00	12.28	1.86	-0.39	10.44
10	9/16/2002	2002Q3	361	3.90	7.89	3.99	4.10	2.31	3.39	3.05	12.03	0.86	-0.25	2.77
11	12/2/2002	2002Q4	285	4.22	7.91	3.69	3.78	2.56	3.23	3.32	11.87	1.24	-0.28	4.91
12	3/19/2003	2003Q1	184	3.98	7.40	3.42	3.02	2.37	3.59	1.95	11.47	0.83	-0.62	4.35
13	6/16/2003	2003Q2	366	3.18	7.50	4.32	**4.82**	2.34	3.74	2.16	12.07	0.90	-0.33	3.28
14	9/18/2003	2003Q3	167	4.19	7.58	3.39	3.81	**2.07**	**2.83**	3.31	10.83	0.35	-0.43	6.59
15	12/10/2003	2003Q4	220	4.30	8.29	3.98	3.70	2.66	3.29	3.40	12.10	1.74	-0.45	2.27
16	3/24/2004	2004Q1	206	3.73	7.83	4.10	4.27	2.37	3.46	2.85	12.02	0.50	-0.29	3.88
17	6/16/2004	2004Q2	177	4.74	7.90	3.16	3.26	2.61	3.10	3.14	11.34	2.14	-0.40	6.21
18	9/10/2004	2004Q3	179	4.19	7.62	3.43	3.31	2.92	3.27	2.61	11.29	2.02	-0.52	8.94
19	12/3/2004	2004Q4	287	4.27	7.57	3.30	3.23	2.66	3.05	3.10	11.17	1.89	-0.37	5.92
20	2/28/2005	2005Q1	272	4.36	7.46	3.10	3.39	2.52	3.06	3.13	11.23	1.29	-0.33	6.62
21	5/31/2005	2005Q2	316	4.00	7.06	3.06	3.00	2.22	3.22	2.39	10.93	0.46	-0.26	6.65
22	8/29/2005	2005Q3	321	4.20	7.28	3.08	2.80	2.61	3.36	2.15	11.06	2.42	-0.52	7.48
23	11/21/2005	2005Q4	338	4.46	6.91	2.45	2.54	2.20	3.48	2.23	11.44	0.41	**-0.23**	9.76
24	3/6/2006	2006Q1	276	4.74	7.17	**2.43**	2.26	2.40	3.44	2.07	11.18	1.02	-0.37	8.70
25	6/1/2006	2006Q2	494	5.11	7.72	2.61	2.89	2.74	3.29	3.00	11.70	1.84	-0.24	**18.02**
26	9/11/2006	2006Q3	460	4.80	7.30	2.50	2.20	2.49	3.32	2.53	11.33	1.32	-0.33	7.83
27	11/21/2006	2006Q4	386	4.58	7.82	3.24	3.42	2.93	3.36	2.94	11.82	1.91	-0.30	6.99
28	3/1/2007	2007Q1	380	4.56	7.72	3.16	3.44	2.39	3.38	2.73	11.67	1.80	-0.39	5.53
29	6/1/2007	2007Q2	419	4.95	7.83	2.88	3.05	2.14	3.21	3.08	11.58	0.56	-0.37	3.58
30	9/7/2007	2007Q3	479	4.38	7.84	3.46	3.62	2.82	3.12	3.33	11.59	1.80	-0.34	5.22
31	11/30/2007	2007Q4	458	3.97	7.85	3.88	4.03	2.75	3.31	2.93	11.70	1.38	-0.32	3.28
32	3/7/2008	2008Q1	381	3.56	7.61	4.05	4.44	2.99	3.21	3.08	11.58	2.23	-0.30	3.94
33	6/13/2008	2008Q2	384	4.27	7.23	2.96	2.73	2.60	3.32	2.44	11.24	1.50	-0.41	9.38
34	9/5/2008	2008Q3	432	3.66	7.29	3.63	3.34	2.79	3.31	2.30	11.06	1.71	-0.42	4.63
35	11/28/2008	2008Q4	534	2.93	7.35	4.42	4.07	3.19	3.73	1.77	11.64	1.94	-0.37	2.81
36	2/26/2009	2009Q1	443	2.98	7.54	4.56	4.02	**4.13**	**4.29**	1.18	**12.54**	1.80	-0.47	5.87
37	5/29/2009	2009Q2	427	3.47	6.96	3.49	3.53	3.12	3.73	1.37	11.26	1.79	-0.42	6.56
38	9/11/2009	2009Q3	536	3.34	6.50	3.16	2.66	2.88	3.87	0.62	10.86	1.82	-0.46	10.82
39	12/11/2009	2009Q4	457	3.55	6.71	3.16	2.45	3.56	3.86	0.64	10.88	2.38	-0.52	9.85
40	2/26/2010	2010Q1	478	3.61	6.56	2.95	2.39	3.28	3.96	0.39	10.86	2.31	-0.68	9.41
41	6/4/2010	2010Q2	444	3.20	6.33	3.13	2.80	3.08	3.90	0.33	10.64	**2.61**	-0.64	9.91
42	9/10/2010	2010Q3	451	2.81	5.59	2.78	**2.19**	2.53	4.21	**-1.16**	9.99	0.77	-0.67	8.65
43	12/10/2010	2010Q4	402	3.32	6.17	2.85	2.68	2.62	3.91	0.26	10.63	1.89	-0.55	10.70
44	3/4/2011	2011Q1	429	3.49	6.45	2.96	2.51	2.92	4.16	-0.27	10.76	2.44	**-0.70**	8.16
45	6/3/2011	2011Q2	406	2.99	6.18	3.19	3.01	2.90	3.90	0.12	10.45	2.09	-0.68	5.17
46	9/9/2011	2011Q3	397	1.93	5.86	3.93	3.07	3.11	3.79	0.04	10.09	2.41	-0.54	**2.02**
47	12/16/2011	2011Q4	439	1.86	5.89	4.03	3.14	2.98	4.07	-0.11	10.68	1.91	-0.36	3.42
48	3/1/2012	2012Q1	406	2.03	6.48	4.45	3.97	2.97	4.07	0.30	11.08	2.25	-0.59	2.71
49	5/30/2012	2012Q2	338	1.63	6.06	4.43	4.37	2.96	3.94	0.00	10.42	1.96	-0.59	2.37
50	9/7/2012	2012Q3	675	1.67	5.66	3.99	3.33	3.00	3.66	-0.01	9.67	2.04	-0.58	2.37
51	12/6/2012	2012Q4	325	**1.59**	**5.46**	3.87	3.41	2.59	3.69	-0.49	**9.25**	1.42	-0.62	3.08
52	3/8/2013	2013Q1	418	2.06	5.97	3.91	3.94	2.73	3.84	-0.14	10.02	2.01	-0.64	4.55
53	5/31/2013	2013Q2	300	2.16	6.43	4.27	3.84	2.91	4.02	0.10	10.76	1.63	-0.67	2.67
54	9/5/2013	2013Q3	404	2.98	6.09	3.11	3.02	2.73	3.41	0.75	9.77	1.71	-0.53	6.68
55	12/5/2013	2013Q4	320	2.88	6.13	3.25	3.12	2.95	3.81	0.18	10.26	1.69	-0.50	7.19
56	3/4/2014	2014Q1	291	2.70	6.43	3.73	3.30	2.63	3.32	1.35	10.13	0.64	-0.69	5.15
57	6/5/2014	2014Q2	325	2.59	6.41	3.82	3.41	3.23	3.76	0.50	10.46	1.89	-0.64	7.08
58	9/4/2014	2014Q3	316	2.45	6.52	4.07	3.55	3.33	3.69	0.90	10.68	2.56	-0.60	3.16
59	12/4/2014	2014Q4	398	2.25	6.46	4.21	4.50	2.51	3.79	0.46	10.51	1.22	-0.59	2.26
60	3/3/2015	2015Q1	414	2.12	6.63	4.51	3.88	3.50	3.72	0.81	10.68	1.92	-0.55	5.80
61	6/4/2015	2015Q2	399	2.31	6.45	4.14	3.69	3.03	3.96	0.20	10.68	1.93	-0.72	4.26
62	9/3/2015	2015Q3	376	2.18	5.96	3.78	2.82	3.17	3.48	0.28	9.49	2.72	-0.72	3.99
63	12/3/2015	2015Q4	347	2.33	6.11	3.78	2.67	3.58	3.55	0.54	9.94	1.92	-0.52	9.22
64	3/3/2016	2016Q1	476	1.83	5.51	3.68	3.17	2.55	3.12	1.04	9.29	0.99	-0.34	3.15
65	6/2/2016	2016Q2	472	1.81	5.83	4.02	3.19	3.24	3.52	0.39	9.71	2.14	-0.63	2.54
	Average of quarters		355	**3.58**	**7.19**	**3.61**	**3.37**	**2.80**	**3.57**	**1.52**	**10.97**	**1.54**	**-0.47**	**5.89**
	Standard deviation			1.18	1.13	0.58	0.63	0.38	0.34	1.33	0.80	0.66	0.15	3.05

B. By individual responses

Survey for		Number of survey responses	10-year bond yield	Total market return forecast	Average risk premium	Median risk premium	Disagreement	Average of individual standard deviations	Average of individuals' worst 10%	Average of individuals' best 10%	Skewness	Average of individuals' asymmetry	% who forecast negative excess return
All dates		23,086	**3.41**	**6.99**	**3.58**	**3.30**	**2.91**	**3.60**	**1.37**	**10.91**	**1.64**	**-0.48**	**5.95**

2.5 Risk premia, weighted average cost of capital and hurdle rates

The risk premia that we measure can be used in the calculation of the cost of capital. In a simple capital asset pricing model, the cost of equity capital would be the product of the company's beta times the risk premium along with the risk free rate. The average firm's cost of equity capital would be 6.63% (assuming a beta=1). Assuming the Baa bond yield is the borrowing rate and a 25% marginal tax rate, the weighted average cost of capital would be about 5.67%.

In previous surveys, we have asked CFOs about their weighted average cost of capital. For example, in March of 2011, companies told us that their internally calculated weighted average cost of capital was 10% (averaged across respondents). At the time, the cost of equity capital was similar to today, 6.45%. The bond yields were higher, with the Baa yielding 6.09%. The average firm (assuming average beta is 1.0) without any debt would have a WACC of 6.45%. When debt is introduced, the WACC would be less than 6.45% -- which is sharply lower than the reported 10%.

Why is there such a divergence? One possible reason is that companies consider other factors in calculating the WACC – perhaps a multifactor model.[4] However, there is no evidence supporting this hypothesis. For example, consultants often add a premium for smaller firms based on the results in many research papers of a size premium. However, in our survey the average WACC for firms with less than $25 million in revenue is 10.6% and the WACC for the largest firms with annual revenue greater than $10 billion is 10.5%.

This analysis was replicated in June of 2012 with similar results. Given the same assumptions, the WACC is 5.37%. However, the average self-reported WACC is 9.3%. Again, there is no evidence of a size premium. The smallest firms reported a WACC of 9.3% and the largest firms 9.7%.

The WACC should not be confused with the investment hurdle rate. The WACC is an analytical calculation that combines a model-based cost of equity (such as the CAPM) and the after-tax cost of debt (reflected in current borrowing rates). Given capital constraints, firms often impose a higher hurdle rate on their investments. For example, to allocate capital to an investment that

[4] Graham and Harvey (2001) find that most companies use a 1-factor model for cost of capital calculations.

promises a projected return exactly at the firm's WACC is equivalent to accepting a zero net present value project.

The June 2012 survey also asked for the investment hurdle rates. They are much higher than the WACCs. The average rate was 13.5% (compared to the survey-reported WACC of 9.3% and the implied WACC from the survey based risk premium of 5.7%. Similar to the WACC results, there is no evidence that the hurdle rates are higher for small firms. Our evidence shows that the reported average hurdle rate for the smallest firms is 13.1% and for the largest firms the rate is 14.2%.

Even though we know from Graham and Harvey (2001) that three quarters of companies use the capital asset pricing model, there is a large gap between an imputed WACC and the WACC that people use. One way to reconcile this is that companies use very long term averages of equity and bond premia in their calculations. For example, suppose the cost of capital is being calculated with averages from 1926. Ibbotson (2013) reports an arithmetic average return of 11.8% over the 1926-2012 period. The average return on corporate bonds is 6.4%. Using the same parameters, we get an imputed WACC of 9.7%. This is very close to the average reported WACC and, indeed, identical to the WACC reported by the largest firms in our survey.

We learn the following: 1) the equity risk premium is much lower today than averages used over long-periods (e.g. from 1926) such as reported in Morningstar (2013) and Duff and Phelps (2015); 2) the survey questions asking directly about a company's WACC is consistent with companies routinely using long-horizon averages for inputs; and 3) WACCs should be thought as lower bounds – the Hurdle Rates used for actual investment decisions are 400bp higher than the stated WACCs.[5]

2.6 Recessions, the financial crisis and risk premia

Our survey spans two recessions: March 2001-September 2001 as well as the recession that begins in December 2007 and ends in June 2009. Financial theory would suggest that risk premia should vary with the business cycle. Premiums should be highest during recessions and lowest

[5] Also see Sharpe and Suarez (2013) and Jagannathan et al. (2016) who analyze our CFO survey data.

during recoveries. Previous research has used a variety of methods including looking at ex post realized returns to investigate whether there is business-cycle like variation in risk premia.

While we only have 60 observations and this limits our statistical analysis, we do see important differences. During recessions, the risk premium is 3.92% and during non-recessions, the premium falls to 3.46%.

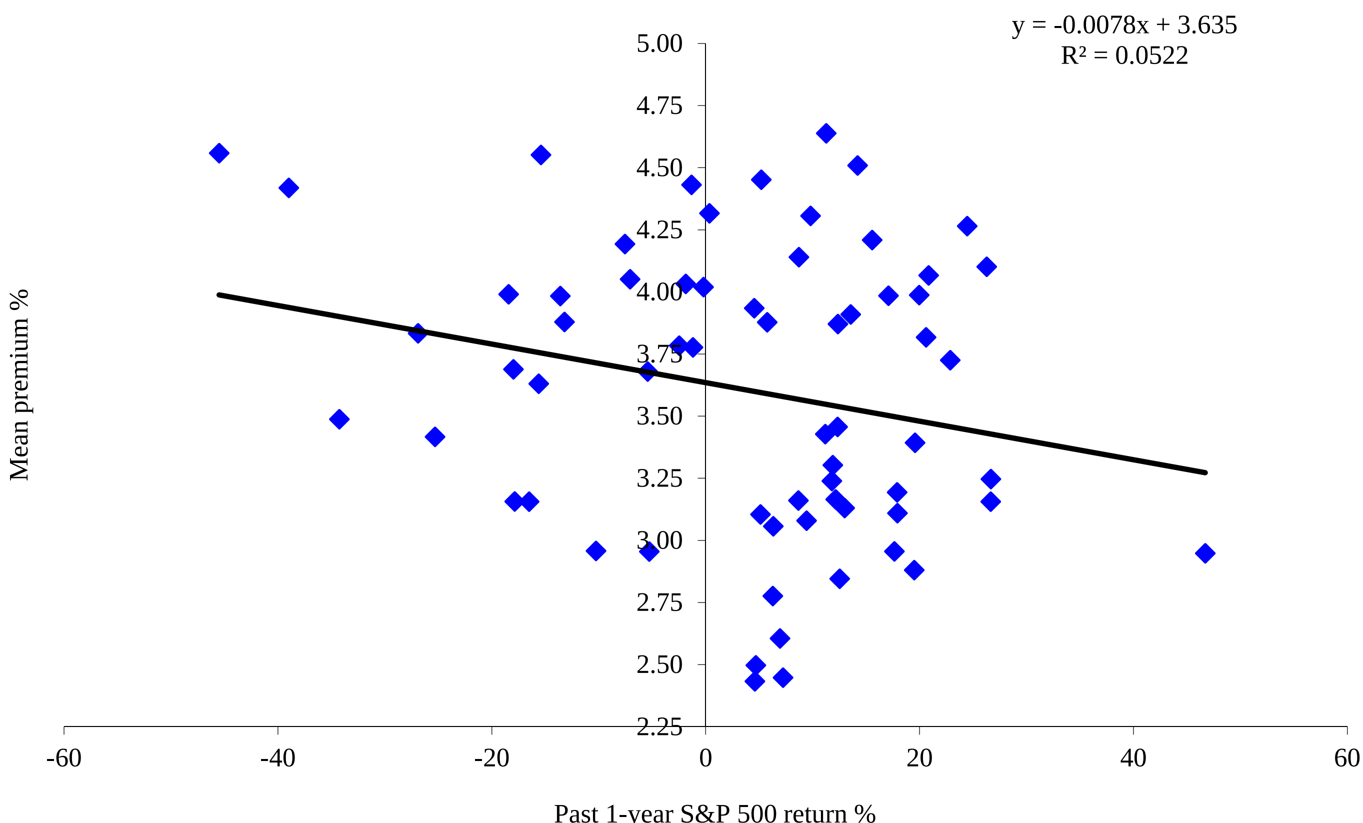
2.7 Explaining variation in the risk premium

While we document the level and a limited time-series of the long-run risk premium, statistical inference is complicated by the fact that the forecasting horizons are overlapping. First, we have no way of measuring the accuracy of the risk premiums as forecasts of equity returns. Second, any inference based on regression analysis is confounded by the fact that from one quarter to the next, there are 36 common quarters being forecasted. This naturally induces a moving-average process.

We do, however, try to characterize the time-variation in the risk premium without formal statistical tests. Figure 2 examines the relation between the mean premium and previous one-year returns on the S&P 500.

Figure 2

The ten-year equity risk premium and past 1-year returns on the S&P 500 index

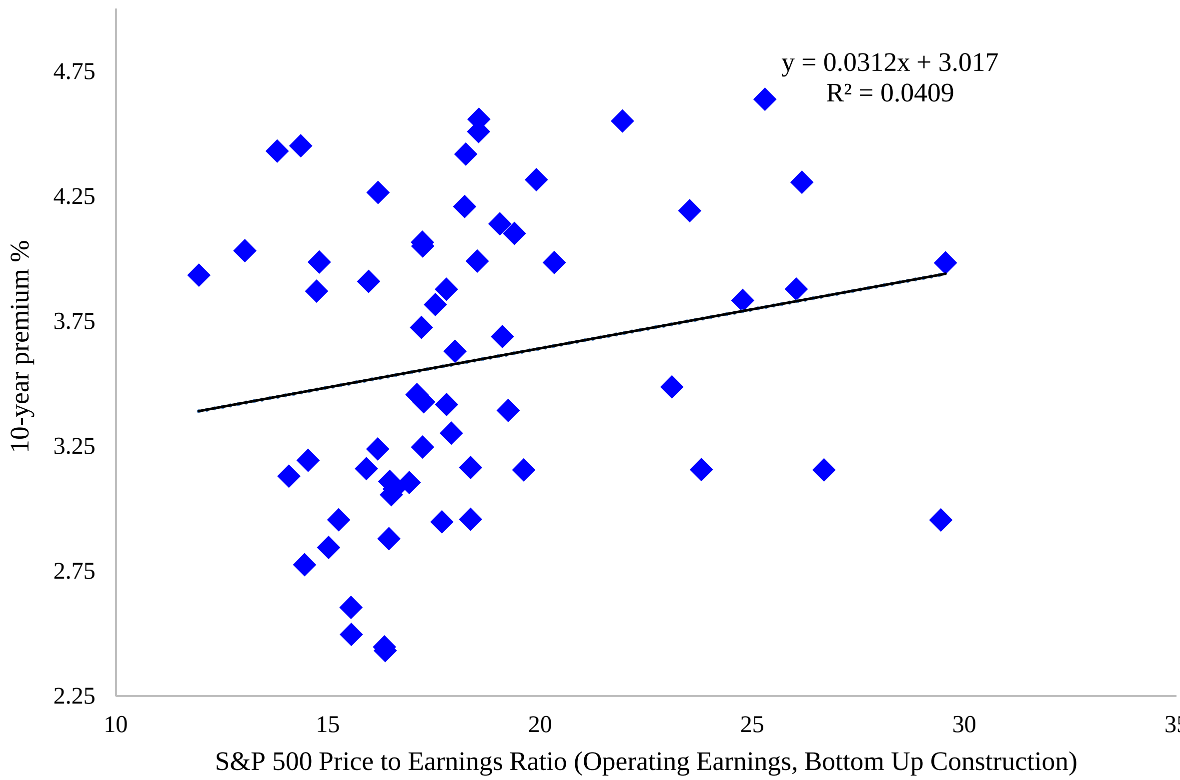


The evidence suggests that there is a weak negative correlation between past returns and the level of the long-run risk premium. This makes economic sense. When prices are low (after negative returns), expected return increase.

An alternative to using past-returns is to examine a measure of valuation. Figure 3 examines a scatter of the mean premium versus the forward price-to-earnings ratio of the S&P 500.

Figure 3

The equity risk premium and the S&P 500 forward price-to-earnings ratio

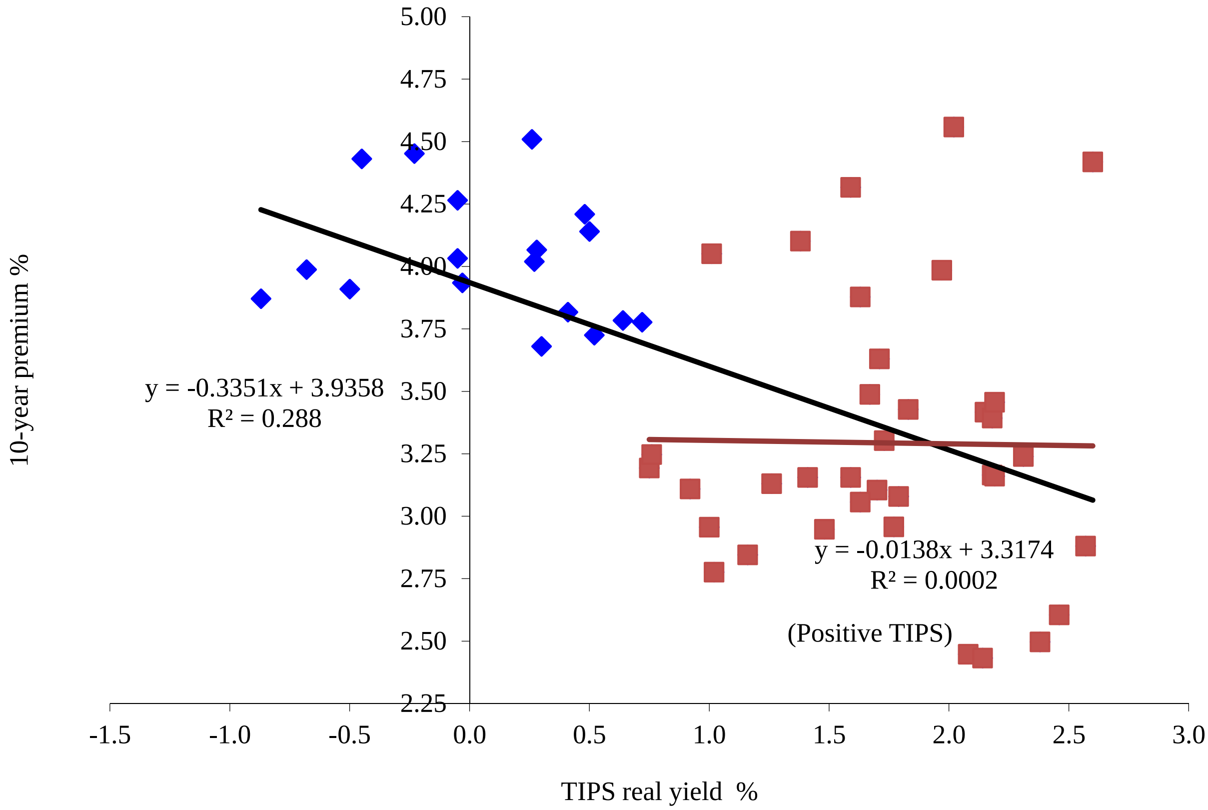


Looking at the data in Figure 3, it appears that the inference may be complicated by a non-linear relation. At very high levels of valuation, the expected return (the risk premium) was low.

We also examine the real yield on Treasury Inflation Indexed Notes. The risk premium is like an expected real return on the equity market. It seems reasonable that there could be a correlation between expected real rates of return stocks and bonds. Figure 4 examines the 10-year on the run yield on the Treasury Inflation Indexed Notes.

Figure 4

The equity risk premium and the real yield on Treasury Inflation Indexed Notes

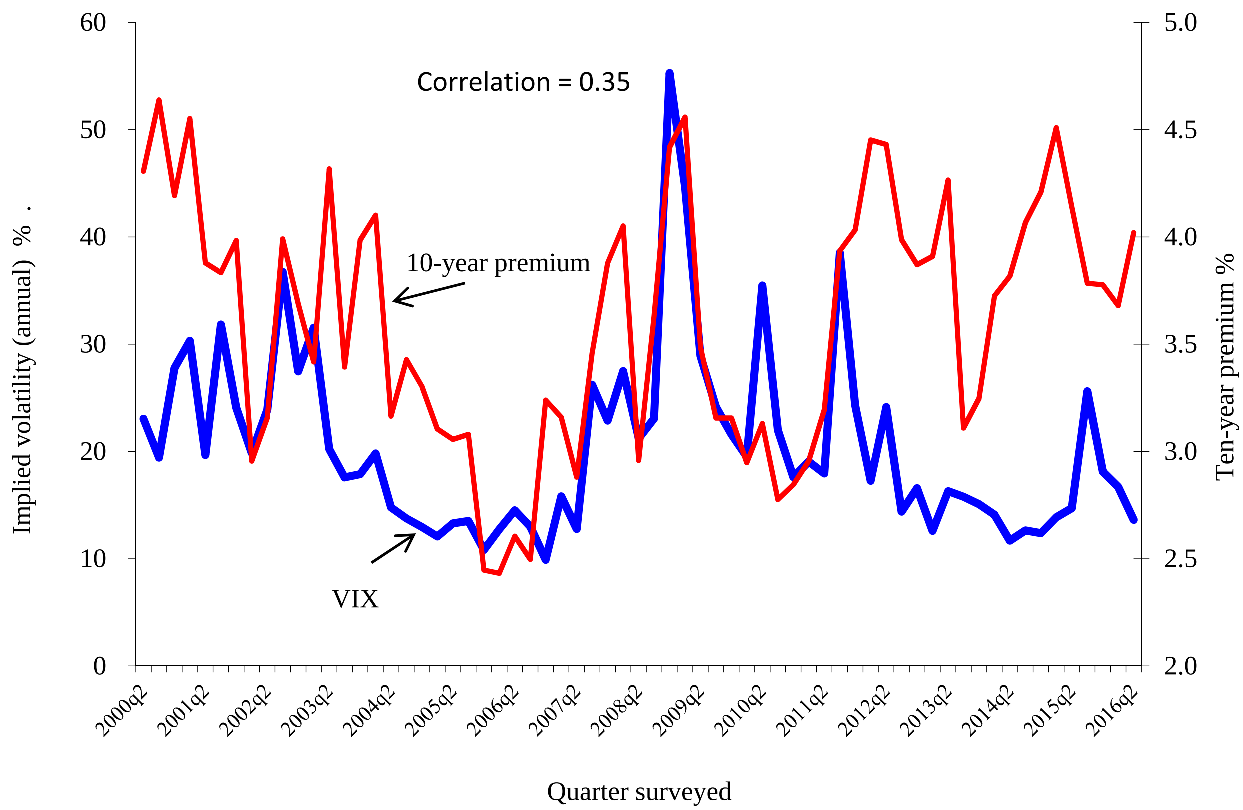


Overall, there is a negative correlation of -0.517. However, this correlation is driven by the negative TIPS yields. This is consistent with the idea that in periods of heightened uncertainty, investors engage in a flight to safety and accept low or negative TIPS yields – and at the same time demand a high risk premium for investing in the equity market.

Finally, we consider two alternative measures of risk and the risk premium. Figure 5 shows that over our sample there is evidence of a strong positive correlation between market volatility and the long-term risk premium. We use a five-day moving average of the implied volatility on the S&P index option (VIX) as our volatility proxy. The correlation between the risk premium and volatility is 0.35. If the closing day of the survey is used, the correlation is roughly the same. Asset pricing theory suggests that there is a positive relation between risk and expected return. While our volatility proxy doesn't match the horizon of the risk premium, the evidence, nevertheless, is suggestive of a positive relation. Figure 5 also highlights a strong recent divergence between the risk premium and the VIX.

Figure 5

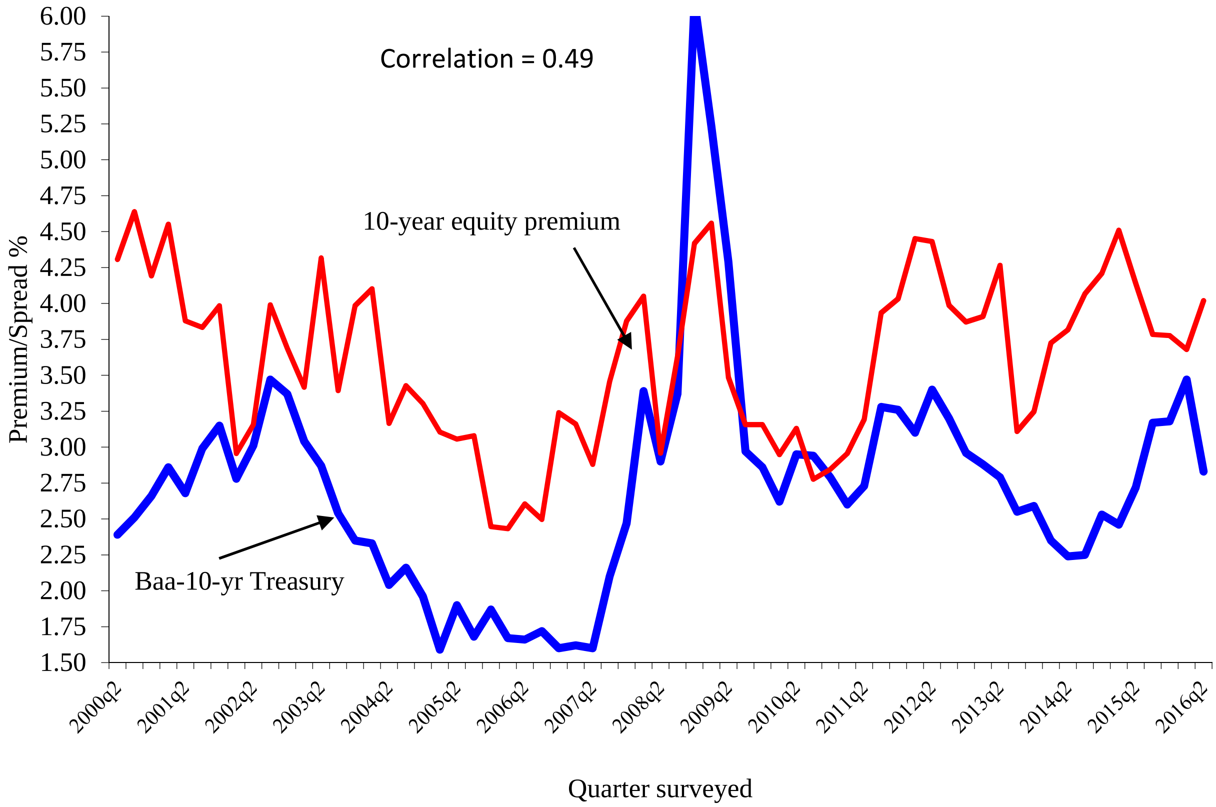
The equity risk premium and the implied volatility on the S&P 500 index option (VIX)



We also consider an alternative risk measure, the credit spread. We look at the correlation between Moody's Baa rated bond yields less the 10-year Treasury bond yield and the risk premium. Figure 6 shows a highly significant relation between the time-series with a correlation of 0.49. Similar to Figure 5, there is a strong recent divergence.

Figure 6

The equity risk premium and credit spreads



2.8 Other survey questions

The June 2016 survey contains a number of other questions. http://www.cfosurvey.org presents the full results of these questions. The site also presents results conditional on demographic firm characteristics. For example, one can examine the CFOs views of the risk premium conditional on the industry in which the CFO works.

2.9 Risk premium data and corporate policies

Research by Ben-David, Graham and Harvey (2013) uses the one-year risk premium forecasts as a measure of optimism and the 80% confidence intervals as a direct measure of overconfidence. By linking email addresses that respondents provide to archival corporate data, Ben-David et al. find that the tightness of the confidence intervals is correlated with corporate investment. Overconfident managers invest more.

Campello, Graham and Harvey (2010) use the survey during the financial crisis and the higher risk premiums to examine the implications of financial constraints on the real activities of the firm. They provide new evidence on the negative impact of financial constraints on firms' investment plans.

Campello, Giambona, Graham and Harvey (2011) use the survey during the financial crisis to study how firms managed liquidity during the financial crisis.

Graham, Harvey and Puri (2013) administer a psychometric test using the survey instrument and link CEO optimism and risk aversion to corporate financial policies.

Graham, Harvey and Puri (2015) use survey data to study how capital is allocated within the firm and the degree to which CEOs delegate decision making to CFOs.

Graham, Harvey and Rajgopal (2005) use survey data to study how managers manipulate earnings. Dichev, Graham, Harvey, and Rajgopal (2013) study earnings quality.

Graham, Harvey, Popadak and Rajgopal (2016) use a similar survey sample to study corporate culture.

2.10 CFO Survey compared to other surveys

Table 2 compares the predictive ability of the Duke-CFO survey with other popular surveys. The table reports the correlations between the current quarter Duke-CFO survey of either optimism about the economy or optimism about the firm's prospects with the subsequent quarter's realization for five surveys: UBS-Gallup, CEO Survey, Conference Board Consumer Confidence, University of Michigan Consumer Confidence and ISM Purchasing Manager's Index. Both of the Duke-CFO optimism measures significantly predict all five of these popular barometers of economic confidence. Related analysis shows that our CFO survey anticipates economic activity sooner (usually one quarter sooner) than do the other surveys.

Table 2
The ability of the Duke CFO survey to predict other surveys

Survey	Predictive correlations: Optimism about economy	Predictive correlations: Optimism about firm's prospects
UBS-Gallup	0.289	0.380
CEO Survey	0.814	0.824
Conference Board Consumer Confidence	0.513	0.767
University of Michigan Consumer Confidence	0.341	0.253
ISM Purchasing Managers Index	0.694	0.497

3. Conclusions

We provide a direct measure of ten-year market returns based on a multi-year survey of Chief Financial Officers. Importantly, we have a 'measure' of expectations. We do not claim it is the true market expectation. Nevertheless, the CFO measure has not been studied before.

While there is relatively little time-variation in the risk premium, premia are higher during recessions and higher during periods of uncertainty. We also link our analysis to the actual investment decisions of financial managers. We are able to impute the weighted average cost of capital given the CFO estimates of equity risk premia, current corporate bond yields and marginal tax rates. This imputed measure is significantly less than the WACCs that CFOs report using in project evaluation. One way to reconcile this is that CFOs use very long-term averages of equity premia and bond rates when calculating WACCs. We provide evidence on the actual hurdle rates used by companies. These hurdle rates are, on average, 400bp higher than the reported WACCs.

While we have over 23,000 survey responses in 16 years, much of our analysis uses summary statistics for each survey. As such, with only 65 unique quarters of predictions and a variable of interest that has a 10-year horizon, it is impossible to evaluate the accuracy of the market excess return forecasts. For example, the June 4, 2007 10-year annual forecast was 7.83% and the realized annual S&P 500 return through June 2, 2016 is 3.2%. Our analysis shows some weak correlation between past returns, real interest rates and the risk premium. In contrast, there is significant evidence on the relation between two common measures of economic risk and the risk premium. We find that both the implied volatility on the S&P index as well as a commonly used measure of credit spreads are correlated with our measured equity risk premium.

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Appendix A

Excerpt from the Survey Instrument

9. On May 17, 2016 the annual yield on 10-yr treasury bonds was 1.8%. Please complete the following:

a. Over the next 10 years, I expect the average annual S&P 500 return will be:

Worst Case: There is a 1-in-10 chance the actual average return will be less than:	**Best Guess**: I expect the return to be:	Best Case: There is a 1-in-10 chance the actual average return will be greater than:
%	%	%

b. During the next year, I expect the S&P 500 return will be:

Worst Case: There is a 1-in-10 chance the actual return will be less than:	**Best Guess**: I expect the return to be:	Best Case: There is a 1-in-10 chance the actual return will be greater than:
%	%	%

Please check one from each category that best describes your company:

a. Industry (choose best option)

- Retail/Wholesale
- Banking/Finance/Insurance/Real Estate
- Mining/Construction
- Transportation & Public Utilities
- Energy
- Services, Consulting
- Agriculture, Forestry, & Fishing
- Public Administration
- Communication/Media
- Tech [software/biotech/hardware]
- Manufacturing
- Healthcare/Pharmaceutical
- Other:

b. Sales Revenue

- Less than $25 million
- $25-$99 million
- $100-$499 million
- $500-$999 million
- $1-$4.9 billion
- $5-$9.9 billion
- More than $10 billion

c. Number of Employees

- Fewer than 100
- 100-499
- 500-999
- 1,000-2,499
- 2,500-4,999
- 5,000-9,999
- More than 10,000

d. Where are you personally located?

- Northeast U.S.
- Mountain U.S.
- Midwest U.S.
- South Central U.S.
- South Atlantic U.S.
- Pacific U.S.
- Canada
- Latin America
- Europe
- Asia
- Africa
- Other

e. Ownership

- Public, NYSE
- Public, NASDAQ/AMEX
- Private
- Government
- Nonprofit

f. Foreign Sales

- 0%
- 1-24%
- 25-50%
- More than 50%

g. What is your company's credit rating?

- Check here if you do not have a rating, and please estimate what your rating would be.

h. Return on assets (ROA=operating earnings/assets) (e.g., -5%, 6.2%)

% Approximate ROA in 2015

% Expected ROA in 2016

i. Your job title (e.g., CFO, Asst. Treasurer, etc.)

WM-4 Duff and Phelps, March 16, 2016, “Client Alert: Duff and Phelps Increases U. S. Equity Risk Premium Recommendation to 5.5%, Effective January 31, 2016”.

Client Alert

March 16, 2016

Duff & Phelps Increases U.S. Equity Risk Premium Recommendation to 5.5%, Effective January 31, 2016

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Section 01

Executive Summary

Executive Summary

5.5%

The Duff & Phelps U.S. Equity Risk Premium Recommendation effective January 31, 2016

Duff & Phelps Increases U.S. Equity Risk Premium Recommendation to 5.5%, Effective January 31, 2016

- Equity Risk Premium: Increased from 5.0% to 5.5%
- Risk-Free Rate: 4.0% (normalized)
- Base U.S. Cost of Equity Capital: 9.5% (4.0% + 5.5%)

The Equity Risk Premium (ERP) is a key input used to calculate the cost of capital within the context of the Capital Asset Pricing Model (CAPM) and other models.[1,2] The ERP is used as a building block when estimating the cost of capital (i.e., “discount rate”, “expected return”, “required return”), and is an essential ingredient in any business valuation, project evaluation, and the overall pricing of risk. Duff & Phelps regularly reviews fluctuations in global economic and financial conditions that warrant periodic reassessments of the ERP.

Based on current market conditions, Duff & Phelps is increasing its U.S. ERP recommendation from 5.0% to 5.5% when developing discount rates as of January 31, 2016 and thereafter until such time that evidence indicates equity risk in financial markets has materially changed and new guidance is issued.

[1] The equity risk premium (ERP), sometimes referred to as the “market” risk premium, is defined as the return investors expect as compensation for assuming the additional risk associated with an investment in a diversified portfolio of common stocks *in excess* of the return they would expect from an investment in risk-free securities.

[2] The cost of capital is the expected rate of return required in order to attract funds to a particular investment.

4.0%

The Duff & Phelps concluded normalized risk-free rate, as of January 31, 2016

Duff & Phelps developed its current ERP recommendation in conjunction with a "normalized" 20-year yield on U.S. government bonds of 4.0% as a proxy for the risk-free rate (R_f) implying a 9.5% (4.0% + 5.5%) "base" U.S. cost of equity capital estimate at the end of January 2016.[3] The use of the spot yield-to-maturity of 2.4% as of January 29, 2016 would result in an overall discount rate that is likely inappropriately low vis-à-vis the risks currently facing investors.[4]

Duff & Phelps last changed its U.S. ERP recommendation on February 28, 2013.[5] On that date, our recommendation was lowered to 5.0% (from 5.5%) in response to evidence that suggested a *reduced* level of risk in financial markets relative to the heightened uncertainty observed in the aftermath of the 2008 global financial crisis, and during the ensuing Euro sovereign debt crisis (which was severely felt from 2010 until 2012).

During 2015, we started seeing some signs of increased risk in financial markets. While the evidence was somewhat mixed as of December, 31, 2015, we can now see clear indications that equity risk in financial markets has increased significantly as of January 31, 2016. Exhibit 1 summarizes the factors considered in our U.S. ERP recommendation.[6]

Exhibit 1: Factors Considered in U.S. ERP Recommendation

Factor	Change	Effect on ERP
U.S. Equity Markets	↓	↑
Implied Equity Volatility	↑	↑
Corporate Spreads	↑	↑
Historical Real GDP Growth and Forecasts	↔	↔
Unemployment Environment	↓	↓
Consumer and Business Sentiment	↔	↔
Sovereign Credit Ratings	↔	↔
Damodaran Implied ERP Model	↑	↑
Default Spread Model	↑	↑

[3] A risk-free rate is the return available on a security that the market generally regards as free of the risk of default. We discuss the background for using a normalized risk-free rate and our concluded normalized risk-free rate in Section 3 "Estimating the Risk-Free Rate", starting on page 9.
[4] The 20-year constant-maturity U.S. Treasury yield was 2.36%, as of January 29, 2016. Source: Board of Governors of the Federal Reserve System website at: http://www.federalreserve.gov/releases/h15/data.htm.
[5] To access the Client Alert report documenting Duff & Phelps' prior U.S. ERP recommendation, visit: www.duffandphelps.com/costofcapital.
[6] Some of the factors in Exhibit 1 are discussed in greater detail later in this report.

Taking these factors together, we find support for increasing our ERP recommendation relative to our previous recommendation.[7]

TO BE CLEAR:

- The Duff & Phelps U.S. ERP recommendation as of January 31, 2016 (and thereafter, until further notice) is 5.5%, matched with a normalized risk-free rate of 4.0%. This implies a 9.5% (4.0% + 5.5%) “base” U.S. cost of equity capital estimate as of January 31, 2016.

- Many valuations are done at year-end. The Duff & Phelps U.S. ERP recommendation for use with December 31, 2015 valuations is 5.0%, matched with a normalized risk-free rate of 4.0%. This implies a 9.0% (4.0% + 5.0%) “base” U.S. cost of equity capital estimate as of December 31, 2015.

[7] The Duff & Phelps ERP estimate is made in relation to a risk-free rate (either “spot” or “normalized”). A “normalized” risk-free rate can be developed using longer-term averages of Treasury bond yields and the build-up framework outlined in Section 3 “Estimating the Risk-Free Rate”, starting on page 9.

Section 02

Overview of Duff & Phelps ERP Methodology

Overview of Duff & Phelps ERP Methodology

A Two-Dimensional Process

There is no single universally accepted methodology for estimating the ERP; consequently there is wide diversity in practice among academics and financial advisors with regards to ERP estimates. For this reason, Duff & Phelps employs a two-dimensional process that takes into account a broad range of economic information and multiple ERP estimation methodologies to arrive at its recommendation.

First, a reasonable range of normal or unconditional ERP is established. Second, based on current economic conditions, we estimate where in the range the true ERP likely lies (top, bottom, or middle).

Long-term research indicates that the ERP is cyclical.[8] We use the term *normal*, or *unconditional* ERP to mean the long-term average ERP without regard to current market conditions. This concept differs from the *conditional* ERP, which reflects current economic conditions.[9] The "unconditional" ERP range versus a "conditional" ERP is further distinguished as follows:

"What is the range?"

- **Unconditional ERP Range** – The objective is to establish a reasonable range for a normal or unconditional ERP that can be expected over an entire business cycle. Based on an analysis of academic and financial literature and various empirical studies, we have concluded that a reasonable long-term estimate of the normal or unconditional ERP for the U.S. is in the range of 3.5% to 6.0%.[10]

"Where are we in the range?"

- **Conditional ERP** – The objective is to determine where within the unconditional ERP range the conditional ERP should be, based on current economic conditions. Research has shown that ERP fluctuates during the business cycle. When the economy is near (or in) a recession, the conditional ERP is at the higher end of the normal, or unconditional ERP range. As the economy improves, the conditional ERP moves back toward the middle of the range and at the peak of an economic expansion, the conditional ERP approaches the lower end of the range.

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[8] See for example John Cochrane's "Discount Rates. American Finance Association Presidential Address" on January 8, 2011, where he presented research findings on the cyclicality of discount rates in general. His remarks were published as Cochrane, J. H. (2011), *Presidential Address: Discount Rates*. The Journal of Finance, 66: 1047–1108.

[9] The "conditional" ERP is the ERP estimate published by Duff & Phelps as the "Duff & Phelps Recommended ERP".

[10] See Shannon P. Pratt and Roger J. Grabowski, *Cost of Capital: Applications and Examples*, Fifth Edition, Chapter 8 "Equity Risk Premium", and accompanying Appendices 8A and 8B, for a detailed discussion of the ERP.

Section 03

Estimating the Risk-Free Rate

Estimating the Risk-Free Rate

The Risk-free Rate and Equity Risk Premium: Interrelated Concepts[11]

A risk-free rate is the return available, as of the valuation date, on a security that the market generally regards as free of the risk of default.

For valuations denominated in U.S. dollars, valuation analysts have typically used the spot yield to maturity (as of the valuation date) on U.S. government securities as a proxy for the risk-free rate. The two most commonly used risk-free bond maturities have been the 10- and 20-year U.S. government bond yields.

The use of (i) long-term U.S. government bonds, and (ii) an ERP estimated relative to yields on long-term bonds most closely match the investment horizon and risks that confront business managers who are making capital allocation decisions and valuation analysts who are applying valuation methods to value a "going concern" business.

The risk-free rate and the ERP are interrelated concepts. All ERP estimates are, by definition, developed *in relation* to the risk-free rate. Specifically, the ERP is the extra return investors expect as compensation for assuming the additional risk associated with an investment in a diversified portfolio of common stocks, compared to the return they would expect from an investment in risk-free securities.

This brings us to an important concept. When developing cost of capital estimates, the valuation analyst should match the term of the risk-free rate used in the CAPM or build-up formulas with the duration of the expected net cash flows of the business, asset, or project being evaluated. Further, the term of the risk-free rate should also match the term of the risk-free rate used to develop the ERP, as illustrated in Exhibit 2.

Exhibit 2: The Risk-Free Rate and ERP Should be Consistent with the Duration of the Net Cash Flows of the Business, Asset, or Project Being Evaluated

Term of risk-free rate used in CAPM or Build-up equation	=	Expected duration of the net cash flows of the business, asset, or project being evaluated	=	Term of risk-free rate used to develop the ERP

[11] This section was extracted from Chapter 3 of the Duff & Phelps *2016 Valuation Handbook – Guide to Cost of Capital* (Hoboken, NJ: John Wiley & Sons, 2016). The discussion in this section was based on information available at the time of writing (through February 23, 2016). Events and market conditions may have changed since then relative to when this report is issued.

In many of the cases in which one is valuing a business, a "going concern" assumption is made (the life of the business is assumed to be indefinite), and therefore selecting longer-term U.S. government bond yields (e.g., 20 years) as the proxy for the risk-free rate is appropriate.

The risk-free rate and the ERP, like all components of the cost of equity capital (and the cost of equity capital itself), are *forward-looking* concepts. The reason that the cost of capital is a forward-looking concept is straightforward: when we value a company (for instance), we are trying to value how much we would pay (now) for the *future* economic benefits associated with owning the company. Since we will ultimately use the cost of capital to discount these future economic benefits (usually measured as expected cash flows) back to their present value, the cost of capital itself must *also* be forward-looking.

Spot Risk-Free Rates versus Normalized Risk-Free Rates

Beginning with the financial crisis of 2008 (the "Financial Crisis"), analysts have had to reexamine whether the "spot" rate is still a reliable building block upon which to base their cost of equity capital estimates. The Financial Crisis challenged long-accepted practices and highlighted potential problems of simply continuing to use the spot yield-to-maturity on a safe government security as the risk-free rate, without any further adjustments.

During periods in which risk-free rates appear to be abnormally low due to flight to quality or massive central bank monetary interventions, valuation analysts may want to consider normalizing the risk-free rate. By "normalization" we mean estimating a risk-free rate that more likely reflects the *sustainable* average return of long-term U.S. Treasuries.

Why Normalize the Risk-Free Rate?

The yields of U.S. government bonds in certain periods during and after the Financial Crisis may have been *artificially* repressed, and therefore likely unsustainable. Many market participants will agree that nominal U.S. government bond yields in recent periods have been artificially low. The Federal Reserve Bank ("Fed"), the central bank of the United States, kept a zero interest rate policy (dubbed "ZIRP" in the financial press) for seven years, from December 2008 until December 2015.

Even members of the Federal Open Market Committee (FOMC) have openly discussed the need to "normalize" interest rates over the last couple of years.[12] For example, at an April 2015 conference, James Bullard, President of the Federal

[12] The FOMC is a committee within the Federal Reserve System, charged under U.S. law with overseeing the nation's open market operations (i.e., the Fed's buying and selling of U.S. Treasury securities).

Reserve Bank of St. Louis, discussed “Some Considerations for U.S. Monetary Normalization”, where he stated:[13]

> *“Now may be a good time to begin normalizing U.S. monetary policy so that it is set appropriately for an improving economy over the next two years.”*

John C. Williams, President of the Federal Reserve Bank of San Francisco (not currently an FOMC member), has also been very vocal about the need to start normalizing interest rates. During 2015, he gave several presentations and speeches, where he mentioned the need to normalize interest rates. For example, in a series of presentations delivered in September and October 2015, he said:[14]

> *“(…) an earlier start to raising rates would allow us to engineer a smoother, more gradual process of policy normalization.”*

In a more recent speech, he acknowledged, however, that even after normalization takes place, interest rates may simply be lower than in pre-Financial Crisis years. Discussing the Fed’s short-term benchmark interest rate (the target federal funds rate), he elaborated on that topic:[15,16]

> *“As we make our way back to normal, we should consider what “normal” will look like for interest rates.(…) The evidence is building that the new normal for interest rates is quite a bit lower than anyone in this room is accustomed to.(...) That doesn’t mean they’ll be zero, but compared with the pre-recession “normal” funds rate of, say, between 4 and 4.5 percent, we may now see the underlying r-star guiding us towards a fed funds rate of around 3–3½ percent instead.”*[17]

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[13] “Some Considerations for U.S. Monetary Policy Normalization”, presentation at the 24th Annual Hyman P. Minsky Conference in Washington, D.C., April 15, 2015. A copy of the presentation can be found here: https://www.stlouisfed.org/~/media/Files/PDFs/Bullard/remarks/Bullard-Minsky-15-April-2015.pdf. For a list of speeches and presentations by President James Bullard, visit: https://www.stlouisfed.org/from-the-president/speeches-and-presentations.

[14] This series of presentations was entitled “The Economic Outlook: Live Long and Prosper”. See for example, the presentation at UCLA Anderson School of Management, Los Angeles, California on September 28, 2015. A copy of the remarks can be found here: http://www.frbsf.org/our-district/press/presidents-speeches/williams-speeches/2015/september/economic-outlook-live-long-and-prosper-ucla/. For a list of speeches and presentations by President John C. Williams, visit: http://www.frbsf.org/our-district/press/presidents-speeches/williams-speeches/.

[15] The federal funds rate is the interest rate at which depository institutions lend balances to each other overnight. The target federal funds rate is a short-term rate and is used as the benchmark interest rate to implement U.S. monetary policies, such as raising or reducing interest rates.

[16] “After the First Rate Hike”, Presentation to California Bankers Association, Santa Barbara, California on January 8, 2016. A copy of the remarks can be found here: http://www.frbsf.org/our-district/press/presidents-speeches/williams-speeches/2016/january/after-the-first-rate-hike-economic-outlook/.

[17] The so-called r* (r-star) stands for the longer-run value of the neutral rate. President Williams defined r-star as essentially what inflation-adjusted interest rates (i.e. real rates) will be once the economy is back to full strength.

While the views of regional Fed Presidents or individual FOMC members do not reflect the official positions of the committee, the reality is that the minutes of 2014 and 2015 FOMC meetings repeated the term “policy normalization” several times, in the context of deciding if and when to raise interest rates.[18]

At its December 15–16, 2015 meeting, the Fed decided to raise the target range for the federal funds rate for the first time in nine years, from a range of 0.00%–0.25% to 0.25%–0.50% (a 25 basis point increase). In support of its decision, the Fed highlighted the considerable improvement in the labor market over the course of the year, and reiterated its expectation that inflation would rise over the medium-term to its target rate of 2.0%.[19]

Even then, officials were very cautious on how to characterize the timing of nominalization policies, seemingly signaling that further increase in interest rates will be gradual.

Nevertheless, in conjunction with the December 15–16, 2015 meeting, FOMC members also submitted their projections of the most likely outcomes for real GDP growth, unemployment rate, inflation, and the federal funds rate for each year from 2015 to 2018 and over the longer run. All of the 17 FOMC participants believed that the target level for the federal funds rate should increase further during 2016, with the median projection suggesting it could rise by another 100 basis points. The median estimate for the longer-term federal funds rate is 3.5% (note: the federal funds rate is a short-term interest rate). However, given the recent headwinds in global financial markets, investors are projecting a much slower pace of rate hikes.[20]

So what does it mean when someone says the current U.S. Treasury yields are not “normal”? And even if interest rates are not considered “normal”, why is that any different from other periods in history? Remember, the risk-free rate is intended to adjust the cost of equity capital for expected future inflation. Typically, valuation analysts use a 20-year U.S. government bond yield when developing a U.S. dollar-denominated cost of equity capital. Therefore, the risk-free rate should reflect an average expected return over those years.

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[18] To access minutes of FOMC meetings visit: http://www.federalreserve.gov/monetarypolicy/fomccalendars.htm.

[19] Minutes of the Federal Open Market Committee December 15–16, 2015”, Board of Governors of the Federal Reserve System. For details visit: http://www.federalreserve.gov/monetarypolicy/fomccalendars.htm.

[20] See, for example, the CME Group FedWatch Tool. The FedWatch Tool is based on CME Group 30-Day Fed Fund futures prices, which are used to express the market’s views on the likelihood of changes in U.S. monetary policy. This tool allows market participants to view the probability of an upcoming federal funds rate hike up to one year out. For details visit: http://www.cmegroup.com/trading/interest-rates/countdown-to-fomc.html.

To be clear, in most circumstances we would prefer using the “spot” yield (i.e., the yield available in the market) on a safe government security as a proxy for the risk-free rate.[21] However, during times of flight to quality and/or high levels of central bank intervention (such as the period beginning with the Financial Crisis) those *lower* observed yields imply a *lower* cost of capital (all other factors held the same), just the opposite of what one would expect in times of relative economy-wide distress and uncertainty. During these periods, using a non-normalized risk-free rate (with no corresponding adjustments to the ERP) would likely lead to an *underestimated* cost of equity capital, and so a “normalization” adjustment may be a reasonable approach to address the apparent inconsistency.

Why isn’t the Current Spot Risk-Free Rate Considered “Normal”?

Part of the reason that U.S. Treasury yields are likely “artificially repressed” is that the “Fed” has been *telling* us that its actions are intended to push rates down, and thus boost asset prices (e.g., stocks, housing). For example, at the September 13, 2012 FOMC press conference, the Fed Chairman at the time, Ben Bernanke, stated:

> *“...the tools we have involve affecting financial asset prices...To the extent that home prices begin to rise, consumers will feel wealthier, they'll feel more disposed to spend ... So house prices is one vehicle. Stock prices – many people own stocks directly or indirectly...and if people feel that their financial situation is better because their 401(k) looks better or for whatever reason, their house is worth more, they are more willing to go out and spend, and that’s going to provide the demand that firms need in order to be willing to hire and to invest.”*

In Exhibit 3, the balance sheet of the U.S. Federal Reserve is shown over time. Since the Financial Crisis, the Fed has been purchasing massive quantities of U.S. Treasuries and mortgage backed securities (MBS) through a series of so-called quantitative easing (QE) measures. At the end of December 2015, the Fed’s balance sheet summed to $4,491,440 million ($4.5 *trillion*), virtually unchanged from December 2014.[22]

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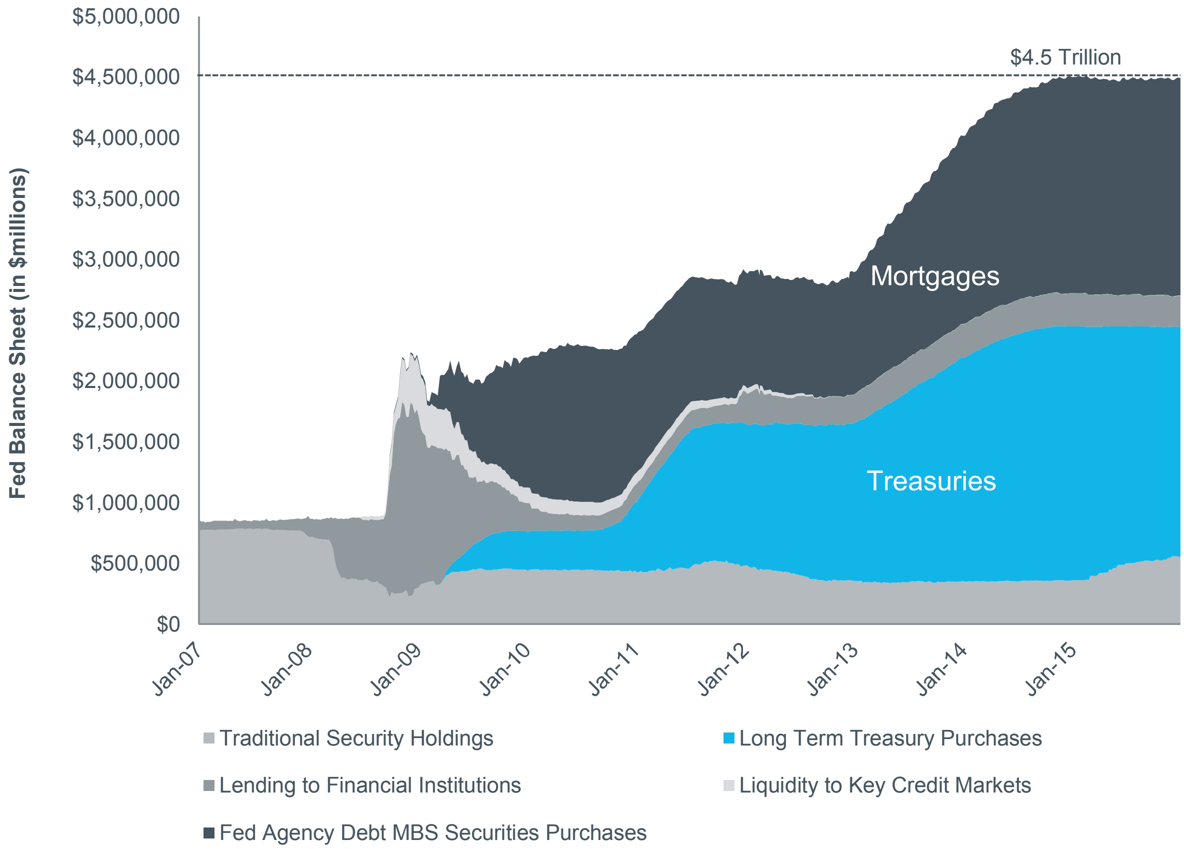
[21] Government bond yields can be found at the Board of Governors of the Federal Reserve System website at: http://www.federalreserve.gov/releases/h15/data.htm.

[22] Source of underlying data: Federal Reserve Bank of Cleveland. To learn more, visit: https://www.clevelandfed.org.

Exhibit 3: Balance Sheet of the Federal Reserve (vis-à-vis Credit Easing Policy Tools)
January 2007–December 2015



In the post-crisis period, some analysts estimated that the Fed's purchases accounted for a growing majority of new Treasury issuance. In early 2013 in the online version of the *Financial Times*, one analyst wrote, "*The Fed, the biggest buyer in the market, has been the driver of artificially low Treasury yields*".[23] In Exhibit 4 we show the aggregate dollar amount of marketable securities issued by the U.S. Department of Treasury (e.g., bills, notes, bonds, inflation-indexed securities, etc.) from 2003 through December 2015. We also display how much of the U.S. public debt is being held by the Fed, foreign investors (including official foreign institutions), and other investors.[24]

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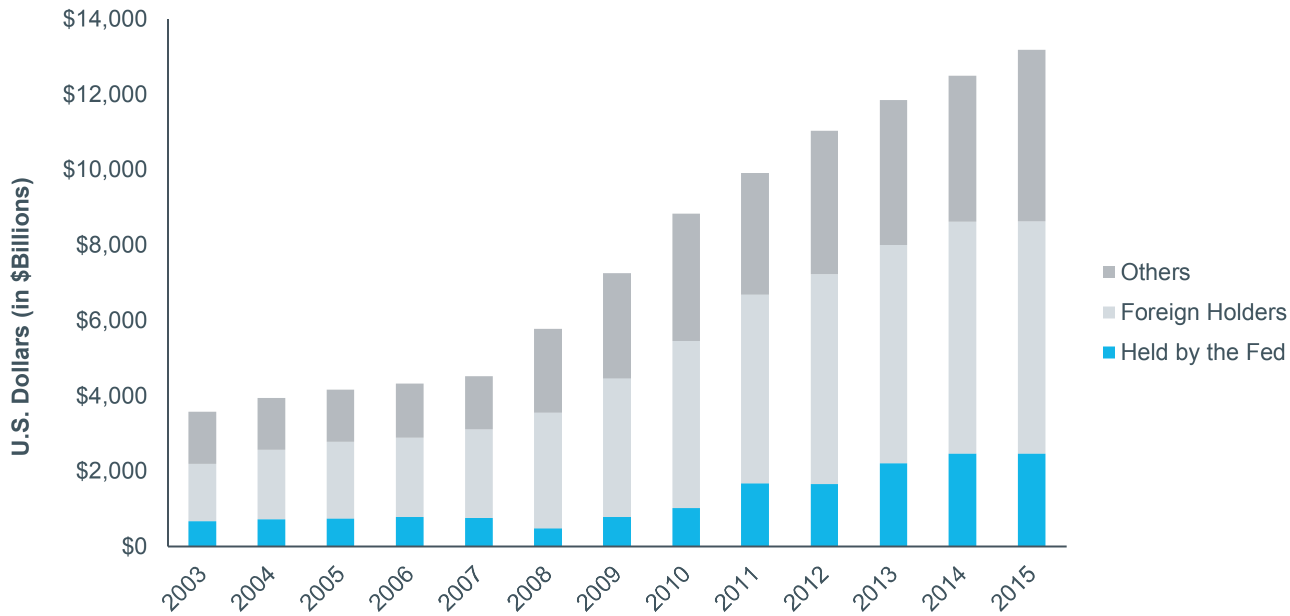
[23] Michael Mackenzie, "Fed injects new sell-off risk into Treasuries", FT.com, January 8, 2013.
[24] Source of underlying data: Federal Reserve Bank of St. Louis Economic Research; U.S. Department of the Treasury. Compiled by Duff & Phelps LLC. Sources included: (i) Board of Governors of the Federal Reserve System (U.S.), U.S. Treasury securities held by the Federal Reserve: All Maturities [TREAST], retrieved from FRED, Federal Reserve Bank of St. Louis at https://research.stlouisfed.org/fred2/series/TREAST/, January 29, 2016; (ii) Monthly Statements of the Public Debt (MSPD) retrieved from https://www.treasurydirect.gov/govt/reports/pd/mspd/mspd.htm, January 29, 2016; and (iii) U.S. Department of the Treasury International Capital (TIC) System's Portfolio Holdings of U.S. and Foreign Securities – A. Major Foreign Holders of U.S. Treasury Securities retrieved from http://www.treasury.gov/resource-center/data-chart-center/tic/Pages/ticsec2.aspx, February 17, 2016.

Exhibit 4: Marketable U.S. Treasury Securities Held by the Public
December 2003–December 2015

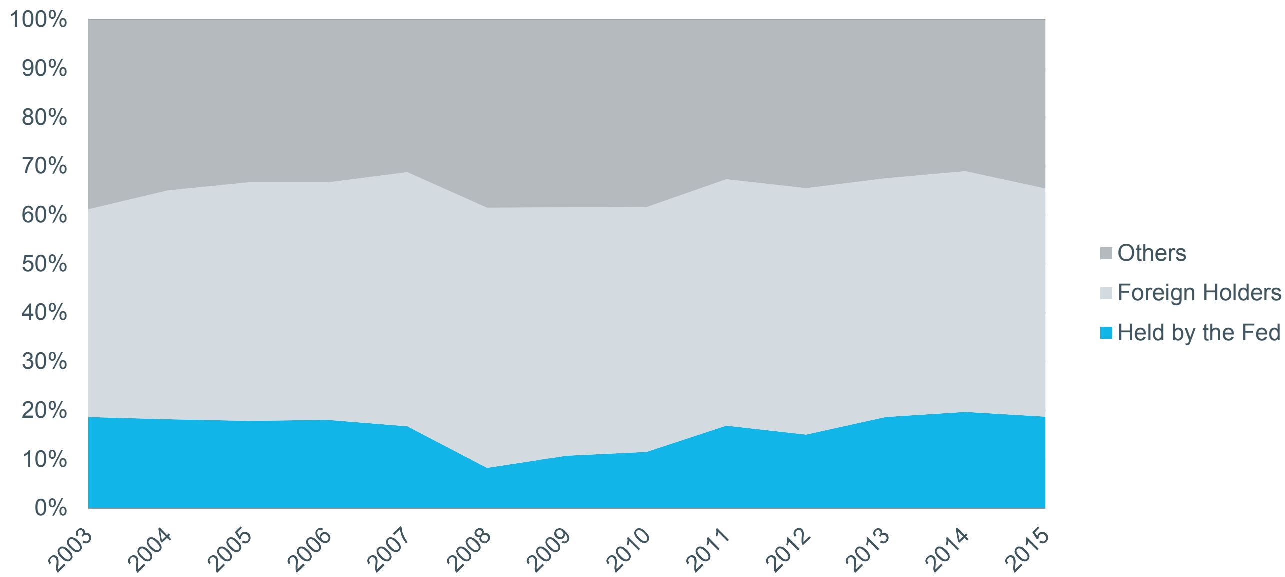


Notably, the issuance of marketable interest-bearing debt by the U.S. government to the public increased almost threefold between the end of 2007 and 2015. Keeping everything else constant (ceteris paribus), the law of supply and demand would tell us that the dramatic increase in supply would lead to a significant decline in government bond prices, which would translate into a surge in yields. But that is not what happened. During the same period, the Fed more than tripled its holdings of U.S. Treasury securities, representing a 16% compound annual growth rate through the end of 2015.[25] Between 2003 and 2008, the Fed's holdings of U.S. Treasuries had held fairly constant in the vicinity of $700 to $800 billion, with December 2008 being the significant exception, when holdings dropped to approximately $476 billion. The first QE program was announced by the FOMC in November 2008, and formally launched in mid-December 2008. After that period, the various QE programs implemented by the Fed have contributed to absorb a sizable portion of the increase in U.S. Treasuries issuance. It is noted that for the first time since 2008, the Fed's holding of marketable U.S. Treasury securities stayed constant at the end of 2015 (in dollar amount) relative to the prior year. Nevertheless, the share held by the Fed at the end of 2015 continues to be at similar levels as those of 2013 and 2014.

[25] If the comparison had been made between 2008 and 2015, the increase would be even more staggering: holdings by the Fed increased 417%, or a 26% compound annual growth rate.

Likewise, broad demand for safe government debt by foreign investors, amid the global turmoil that followed the Financial Crisis, has absorbed another considerable fraction of new U.S. Treasuries issuance. How significant are these purchases by the Fed and foreign investors? Exhibit 5 shows the same information as in Exhibit 4, but displays the relative share of each major holder of marketable U.S. Treasuries since 2003 until 2015.[26]

Exhibit 5: Relative Holdings of Marketable U.S. Treasury Securities Held by the Public (in percentage terms)
December 2003–December 2015



At the end of 2015, the relative share of U.S. Treasuries held by the Fed and foreign investors was almost 19% and 47% respectively, for a combined 65%. This combined level is actually close to the 69% observed at the end of 2007, prior to the onset of the Financial Crisis. However, as indicated above, the dollar amount of U.S. Treasuries has tripled after 2007, meaning that the Fed and foreign investors have absorbed over two-thirds of the available stock in the post-crisis period. Interestingly, a look at the composition of foreign investors reveals that since 2006 over two-thirds are actually foreign official institutions (i.e., central banks and central governments of foreign countries).[27,28] Thus, a great majority of U.S. Treasuries are currently being held by either foreign government arms or central banks around the world (including the Fed).

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[26] Source of underlying data: Federal Reserve Bank of St. Louis Economic Research; U.S. Department of the Treasury. Compiled by Duff & Phelps LLC.
[27] Source: Treasury International Capital (TIC) System's Portfolio Holdings of U.S. and Foreign Securities – A. Major Foreign Holders of U.S. Treasury Securities retrieved from http://www.treasury.gov/resource-center/data-chart-center/tic/Pages/ticsec2.aspx, February 17, 2016.
[28] For a description of foreign official institutions, visit "TIC Country Codes and Partial List of Foreign Official Institutions" at: http://www.treasury.gov/resource-center/data-chart-center/tic/Pages/foihome.aspx.

A team of researchers has recently studied the impact that this massive amount of U.S. Treasury purchases by foreign investors and the Fed have had on long-term real rates. Specifically, using data through November 2012, the authors estimated that by 2008 foreign purchases of U.S. Treasuries had cumulatively reduced 10-year real yields by around 80 basis points. The subsequent Fed purchases through the various QE programs implemented in the 2008–2012 period was estimated to incrementally depress 10-year real yields by around 140 basis points. Combining the impact of Fed and foreign investor purchases of U.S. Treasuries, real 10-year yields were depressed by 2.2% at the end of 2012, according to these authors' estimates.[29]

When the Fed concluded its third round of QE measures (in October 2014) and signaled that an increase in the target federal funds rate might be on the horizon, the salient question was what would happen to rates as one of the largest purchasers in the market (the Fed) discontinued its QE operations. All other things held the same, rates would be expected to rise. But again, that is not what happened. In fact, the yield on 10-year U.S. Treasury bonds dropped from 2.4% at the end of October to 2.2% at the end of December 2014. Likewise, the 20-year yield dropped from 2.8% to 2.5% over the same period. Even more concerning is the behavior of interest rates following the Fed's decision on December 16, 2015 to raise its target range for the federal funds rate for the first time in nine years. At first, the yield on 10- and 20-year U.S. Treasury bonds increased, reaching 2.3% and 2.7% respectively at December 31, 2015. In fact, yields had already been rising since October 2015, in anticipation of such a rate hike decision. However, by January 31, 2016, 10- and 20-year yields were back at 1.9% and 2.4%, respectively.

Why is that?

It may be useful to first distinguish short-term drivers versus long-term trends in interest rates.

It is almost undisputed that aggressive monetary policies implemented as a response to the Financial Crisis drove long-term interest rates in the U.S. and several advanced economies to historically low levels. But many economists claim that the current low rate environment is not just a cyclical story and that we can expect to see a lower level of interest rates in the long term (although not as low as today's). A number of explanatory factors and theories have emerged, some more pessimistic than others.

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[29] Kaminska, Iryna and Zinna, Gabriele, "Official Demand for U.S. Debt: Implications for U.S. Real Interest Rates". IMF Working Paper No. 14/66 (April 2014).

It is not our place to select which, amongst the various theories, is more (or less) correct. Instead, we suggest that valuation specialists read different sources to get acquainted with such theories. A recent survey conducted by the Council of Economic Advisers lists various factors that could help explain why long-term interest rates are currently so low. According to the study, the following is a list of possible factors, bifurcated between those that are likely transitory in nature and those that are likely longer-lived:[30, 31]

Factors that Are Likely Transitory

- Fiscal, Monetary, and Foreign-Exchange Policies
- Inflation Risk and the Term Premium
- Private-sector Deleveraging

Factors that Are Likely Longer-Lived

- Lower Global Long-run Output and Productivity Growth
- Shifting Demographics
- The Global "Saving Glut"
- Safe Asset Shortage
- Tail Risks and Fundamental Uncertainty

The report concludes that it remains an open question whether the underlying factors linked to the currently low rates are transitory, or do they imply that the long-run equilibrium for long-term interest rates is lower than before the Financial Crisis.

The bottom line is that the future path of interest rates is currently uncertain.[32] So, for now, we will focus on some the factors that may be keeping interest rates ultra-low in the near term and discuss whether one can expect an increase from these levels in the medium term.

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[30] The Council of Economic Advisers, an agency within the Executive Office of the President of the United States, is charged with providing economic advice to the U.S. President on the formulation of both domestic and international economic policy.

[31] "Long-Term Interest Rates: A Survey", July 2015. The full report can be accessed here: https://www.whitehouse.gov/sites/default/files/docs/interest_rate_report_final_v2.pdf. See also "The Decline in Long-Term Interest Rates", July 14, 2015, a short blog article by Maurice Obstfeld and Linda Tesar discussing the various possible drivers of low long-term interest rates listed in the report. The article can be accessed here: https://www.whitehouse.gov/blog/2015/07/14/decline-long-term-interest-rates.

[32] For another analysis of current long-term interest rates, see Jonathan Wilmot, "When bonds aren't bonds anymore", *Credit Suisse Global Investment Returns Yearbook 2016*, February 2016.

First of all, the size of the Fed's balance sheet is still considered enormous by historical standards and the Fed has expressed the intent to keep its holdings for a long time. For example, at its December 2015 meeting, when announcing the increase by 25 basis points of the target range for the federal funds rate from 0.00%–0.25% to 0.25%–0.50%, the FOMC still stated that:[33]

> *"The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction, and it anticipates doing so until normalization of the level of the federal funds rate is well under way. This policy, by keeping the Committee's holdings of longer-term securities at sizable levels, should help maintain accommodative financial conditions."*

Translation: the Fed is keeping the size of its balance sheet constant for the foreseeable future, because it still wants to keep long-term interest rates low.

A report released in November 2014 (following the conclusion of QE3) by Standard & Poor's (S&P) appears to concur with our interpretation:[34]

> *"Since QE works via a stock effect, as long as a central bank is maintaining a certain stock of QE, it is still "doing" QE. If a central bank has reached the maximum point of expanding its balance sheet, it is a little perverse to describe it as having "ended QE." Rather, what it will have ended are the asset purchases required to get it to the point of having done the maximum amount of QE it has decided to put in place."*

So, while the process of rate normalization has formally begun, the Fed is planning for a very gradual increase in interest rates. For example, in the minutes of the same December 2015 meeting, the FOMC also stated that:

> *"The Committee expects that economic conditions will evolve in a manner that will warrant only gradual increases in the federal funds rate; the federal funds rate is likely to remain, for some time, below levels that are expected to prevail in the longer run."*

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[33] Press Release of FOMC's Monetary Policy Statement, December 16, 2015. For details visit: http://www.federalreserve.gov/monetarypolicy/fomccalendars.htm.

[34] S&P *Ratings Direct* report entitled "Economic Research: The Fed Is Continuing, Not 'Ending,' Quantitative Easing", November 4, 2014.

Secondly, another phenomenon has helped push U.S. interest rates lower over time: purchases of U.S. Treasury securities by foreign investors have grown at a fast pace over the last several years.[35] While 2015 was the first time in many years when net purchases increased by only a negligible amount, the reality is that the total share of U.S. Treasuries owned by foreign investors is still very high (refer back to Exhibit 4). Should foreign demand for U.S. Treasury securities drop, it would still take some years for such significant holdings to be unwound (especially given the level of globalization of the world economy). Notably, there are academic studies that document a significant impact of foreign investors on U.S. interest rates even prior to the onset of 2008 Financial Crisis. One such study (not to be confused with the research cited above) estimated that absent the substantial foreign inflows into U.S. government bonds, the (nominal) 10-year Treasury yield would be 80 basis points higher using data through 2005.[36] The impact of foreign financial flows on long-term interest rates is not confined to the U.S. A recent research paper estimates that the increase in foreign holdings of Eurozone bonds between early 2000 and mid-2006 is associated with a reduction of Eurozone long-term interest rates by 1.55%.[37]

Thirdly, an environment of geopolitical and economic uncertainty led to flight to quality movements during certain periods of 2015, which helped drive interest rates even lower for major safe havens countries. Flight to quality has been particularly acute in early 2016.

Global investors had enough reasons to seek safe haven investments during 2015. In general, political conflicts continued in 2015 in various regions of the world. Major examples include (i) the face-off between the Eurozone and Greece's new radical left-leaning government, which culminated in Greece defaulting on its sovereign debt with the International Monetary Fund (IMF), being forced to accept a third bail-out package, and barely escaping an exit from the Eurozone; (ii) the escalation of the civil war in Syria, leading to a refugee crisis, with an increasing number of refugees seeking asylum in neighboring Middle Eastern countries and in the European Union; and (iii) the strengthening of the Islamic State of Iraq and Syria (ISIS), which continued to launch terrorist attacks across the globe, with the greatest shock felt in November when ISIS carried out a series of coordinated attacks in Paris, France.

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[35] Source: Treasury International Capital (TIC) System's Portfolio Holdings of U.S. and Foreign Securities – A. Major Foreign Holders of U.S. Treasury Securities retrieved from http://www.treasury.gov/resource-center/data-chart-center/tic/Pages/ticsec2.aspx, February 17, 2016.

[36] Warnock, Francis E., and Veronica Cacdac Warnock, "International Capital Flows and U.S. Interest Rates," *Journal of International Money and Finance* 28 (2009): 903-919.

[37] Carvalho, Daniel and Michael Fidora, "Capital inflows and euro area long-term interest rates", ECB Working Paper 1798, June 2015. Note that the 'euro' was introduced to financial markets on January 1, 1999 as the new 'single currency' of what is now known as the Eurozone.

In addition, concerns about a slowing global economy and deflationary pressures have also led global investors to seek safe haven investments, such as government bonds issued by the U.S., Germany, and Switzerland, to name a few. Oil prices continued to tumble from its mid-2014 highs, reinforcing investor anxiety over stagnant growth in the Eurozone and Japan, as well as a deceleration in China and several other emerging-market countries.

Mid-August 2015 caught global markets by surprise, when China announced a devaluation of the yuan, following dramatic sell-offs of Chinese equities throughout the month of July. The surprise yuan devaluation was followed by a few days of disappointing news about China's economy. The apparent slowdown in China's economy (i) raised fears of a further global economic slowdown, (ii) significantly depressed commodity prices (China is the world's largest importer of several raw materials), and (iii) weighed heavily on world financial markets. The Fed's announcement in September that it would not raise rates (when the market participant consensus had been predicting a rate hike), took into consideration the increased economic uncertainty implied by the tumult observed in global markets.

On the other hand, the sharp decline in oil prices has put additional pressure in an already very low inflation environment, considered by many as bordering on deflation territory. For perspective, the price of Brent crude oil was at $115/barrel in mid-June 2014; since then prices declined to $38/barrel at the end of 2015, a cumulative 67% decline in the space of a year and a half. The collapse of oil prices has continued in early 2016.[38] The potential benefit of lower oil prices to oil-importing nations has not (yet, at least) been felt on economic growth. Worryingly, should major economic regions such as the Eurozone enter into a deflationary path, one could use Japan's "lost decades" as a parallel to what might happen in the future.

Deflation risks and economic stagnation are precisely what led central banks in Japan and Eurozone to recently boost their respective monetary easing policies. In October 2014, Japan's central bank surprised the world by announcing a second easing program self-dubbed as "quantitative and qualitative easing" (QQE).[39] In November, after the announcement of a second consecutive quarter of economic contraction, Japan's prime minister Shinzo Abe also proclaimed snap parliamentary elections, explicitly seeking endorsement to continue with the government's expansionary economic policies (also known as "Abenomics"). While Abe's party managed to keep its two-third majority in the December 2014 elections, the QQE measures failed to spur real economic growth in 2015, with headline inflation far below the Bank of Japan's (BOJ) 2.0% target.

[38] Source: S&P *Capital IQ* database.
[39] For a list of BOJ's monetary policy decisions, visit: http://www.boj.or.jp/en/mopo/mpmdeci/index.htm/.

In another surprise move, the BOJ announced on January 29, 2016 a landmark decision to implement a negative interest rate policy (dubbed "NIRP" in the financial press), in conjunction with its QQE. The BOJ now joins the European Central Bank (ECB), as well as the Danish, the Swedish, and the Swiss central banks in adopting this new form of unconventional monetary policies. NIRP entails financial institutions paying interest on the liabilities that the central bank issues to them. The main idea of NIRP is to discourage savings, while creating incentives for consumers to increase their spending and companies to expand their investment. However, the consequence of such measures is to also pressure interest rates further downwards. According to an S&P research report:[40]

> *"Negative interest rate policy appears to be able to exert downward pressure on the whole yield curve via the portfolio rebalance effect, as security prices, perturbed by the central bank's fixing of one price, adjust to restore equilibrium."*

According to recent Bloomberg calculations, more than $7 trillion of government bonds globally offered negative yields in early February 2016, making up about 29% of the Bloomberg Global Developed Sovereign Bond Index.[41]

In the Eurozone, lackluster growth trends, coupled with deflation fears, induced the ECB to cut its benchmark rate to a new record low in early June 2014, while also announcing an unprecedented measure to charge negative interest rates on deposits held at the central bank.[42] Responding to a weak third quarter, the ECB again cut its benchmark rate to 0.05% in September 2014, and revealed details for two different securities purchase programs. The continued threat of deflation led the ECB to announce a larger scale sovereign debt buying program in January 2015, consisting of €60 billion in monthly asset purchases. This program was launched in March with an original target end-date of September 2016. Real GDP growth did accelerate in the first quarter of 2015, with consumer price inflation and job growth also showing signs of improvement. However, growth decelerated once again in the second and third quarters. The November terrorist attacks in Paris, the Syrian refugee crisis, and the mounting political uncertainty in Spain and Portugal were all risk factors affecting the Eurozone at the end of 2015. Inflation was also virtually stagnant in October and November. As a result, the ECB announced on December 3, 2015 a further cut of the already-negative deposit facility rate and an extension of monthly asset purchases to March 2017; markets were nevertheless disappointed, as a further expansion of the QE program had been anticipated.

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[40] Standard & Poor's *Ratings Direct* report entitled "Negative Interest Rates: Why Central Banks Can Defy 'Time Preference'", February 3, 2016.

[41] World's Negative-Yielding Bond Pile Tops $7 Trillion: Chart", February 9, 2015. This article can be accessed here: http://www.bloomberg.com/news/articles/2016-02-09/world-s-negative-yielding-bond-pile-tops-7-trillion-chart.

[42] For a list of ECB's monetary policy decisions, visit: https://www.ecb.europa.eu/press/govcdec/html/index.en.html.

Markets are now expecting the ECB to expand its QE policies at its March 2016 meeting.[43]

The current economic conditions in the Eurozone and Japan are in stark contrast with the recent performance of the U.S. economy. Over the last two years, the U.S. economy has been expanding at a healthy pace (albeit below its long-term potential). That, coupled with solid jobs gains, made the Fed more confident that a rise in short-term interest rates was in order, back in December 2015. The divergence in economic growth and monetary policies in the U.S. versus other major economic regions is actually contributing to some of the decline in U.S. Treasury yields. Ultimately, U.S. government bonds continue to offer more-attractive yields than bonds issued by other safe-haven countries, and a stronger dollar enables foreign investors to pick up extra returns on U.S. investments.

Looking forward to 2016, many of the forces behind disappointing U.S. stock market performance during 2015, such as low commodity prices, sluggish global growth, and shrinking corporate profits (partly due to a strong U.S. dollar), may still be present in the coming year. This could contribute to a downward pressure in global interest rates, including those in the U.S.

So, are artificially repressed U.S. Treasury yields sustainable? Sustainability implies that something can go on forever, but Stein's Law tells us that "If something cannot go on forever, it will stop".[44] A possible corollary of Stein's Law is that if the accommodative monetary policy (including the massive QE programs) by the Fed since the Financial Crisis "cannot go on forever", then the Fed may really not have much of a choice in whether to "stop" or not. Put simply, things that are destined to stop will stop by their own accord, one way or another. Whether it will be a "graceful dismount" is yet to be seen.

In the short-term, there are probably still enough significant factors that will keep interest rates at artificially low levels. However, in the medium-term, borrowing any major setback in the global economy, investors seem to be expecting U.S. interest rates to start rising, albeit slowly, after 2016.

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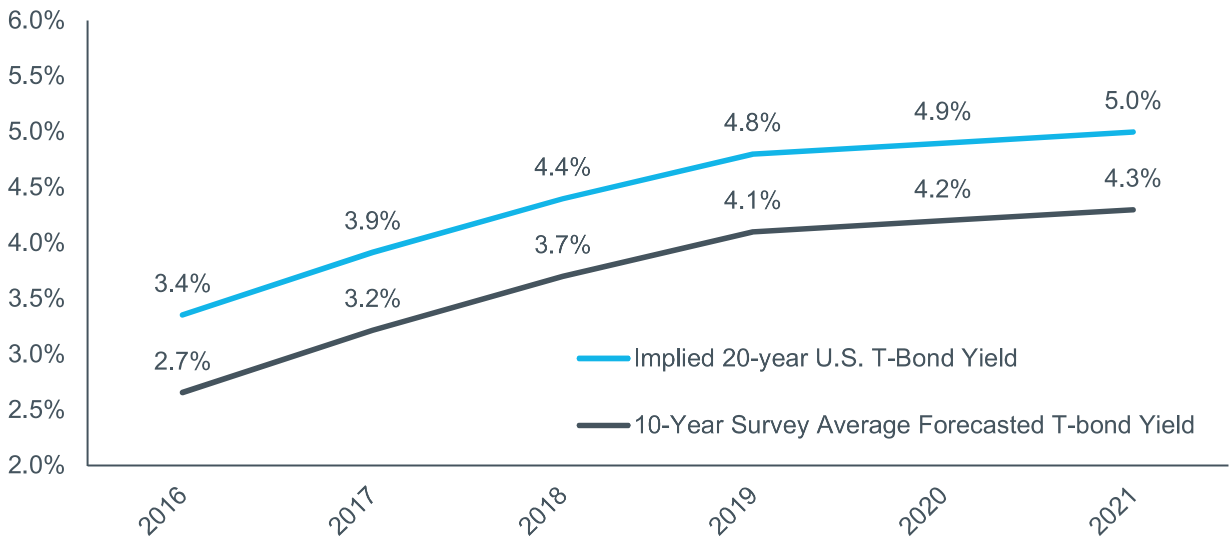
[43] The discussion in this section was based on information available at the time of writing (through February 23, 2016). Events and market conditions may have changed since then relative to when this report is issued.

[44] Professor Herbert Stein was a member and later chairman of the Council of Economic Advisers under Presidents Nixon and Ford. Source: Michael M. Weinstein, "Herbert Stein, Nixon Adviser And Economist, Is Dead at 83", *New York Times*, September 09, 1999.

We compiled consensus forecasts from reputable sources published close to year-end 2015. Exhibit 6 displays the average of consensus forecasts for 10-year U.S. Treasury bond yields through 2021 from a variety of surveys.[45,46,47] We then added a maturity premium to the 10-year yield, to arrive at an implied forecast for the 20-year government bond yield.[48]

Exhibit 6: Average forecasted 10-year U.S. Treasury Bond Yield and Implied 20-year U.S. Risk-free Rate (in percentage terms) at year-end 2015



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[45] Sources: "Survey of Professional Forecasters: Fourth Quarter 2015", Federal Reserve Bank of Philadelphia (November 13, 2015); "The Livingston Survey: December 2015", Federal Reserve Bank of Philadelphia (December 10, 2015); "US Consensus Forecast ", Consensus Economics Inc. (January 11, 2016); *Blue Chip Economic Indicators* (January 10, 2016); *Blue Chip Financial Forecasts* (December 1, 2015); S&P *Capital IQ*™ database. Note that while some of the sources were released in 2016, the underlying surveys had been conducted in early January 2016, still reflecting expectations close to year-end 2015.

[46] Not all surveys provided consensus forecasts through 2021. At a minimum, all five sources included forecasts for 2016.

[47] Sources of underlying data: Survey of Professional Forecasters; Livingston Survey; U.S. Consensus Forecast; *Blue Chip Economic Indicators*; and *Blue Chip Financial Forecasts*; S&P *Capital IQ* database. Compiled by Duff & Phelps LLC.

[48] A maturity premium of approximately 70 basis points was added to the 10-year yield. This was based on the average yield spread between the 20 and the 10-year U.S. Treasury constant maturity bonds from December 2008 through December 2015. Had more recent data been used, when the yield spread declined to a range of 40 to 50 basis points, this would not have materially changed our main conclusion. While the magnitude of the maturity premium can be debated, using even the most recent 40 to 50 basis points average yield spread would imply that at year-end 2015 market participants expected the 20-year yield to reach close to 4.1% by 2018 (3.7% + approximately 0.4%).

The Congressional Budget Office (CBO), a non-partisan agency supporting the U.S. Congressional budgeting process, is more optimistic on how fast rates will rise. In its report “The Budget and Economic Outlook: 2016 to 2026”, the CBO estimates the 10-year yield to average 3.5% in 2017, which would imply a 20-year yield around 4.2% using a maturity premium of 70 basis points. Its long-term forecast for the 10-year yield is 4.1% starting in 2019, again implying a long-term 20-year yield around 4.8%.[49]

Methods of Risk-free Rate Normalization

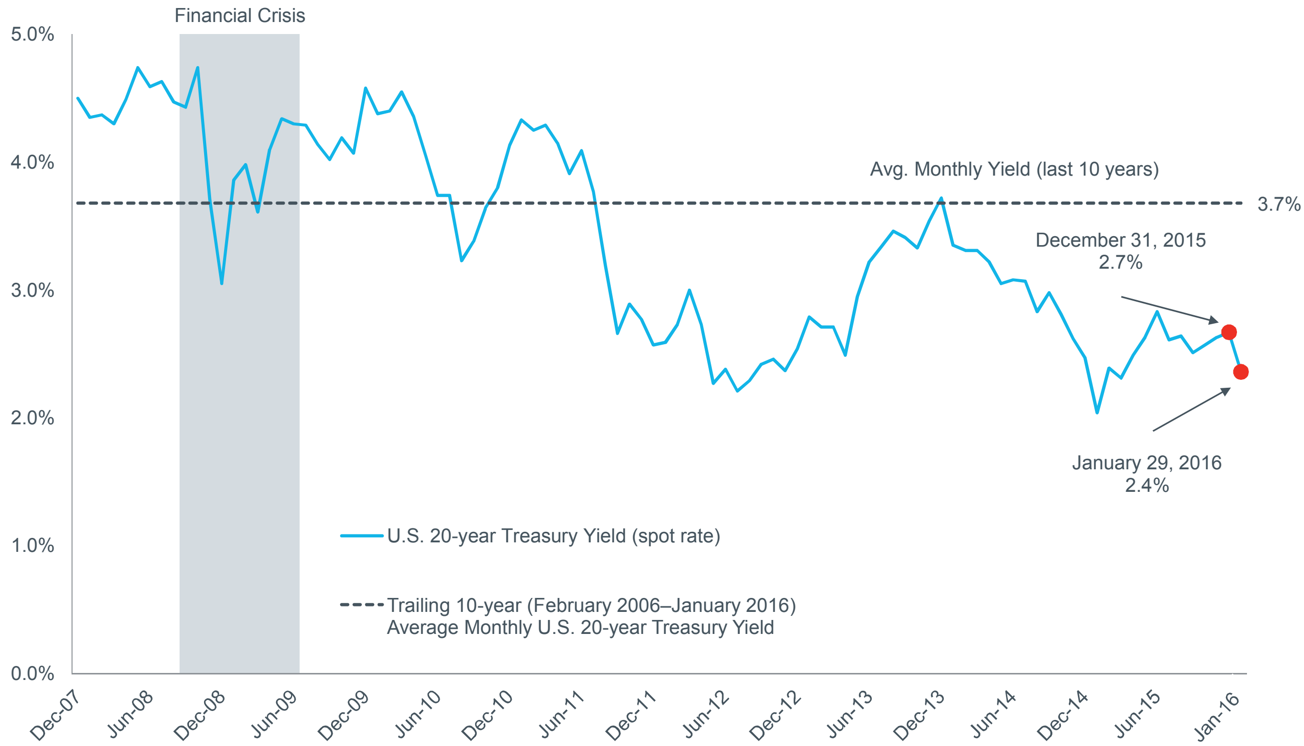
Normalization of risk-free rates can be accomplished in a number of ways, including (i) simple averaging, or (ii) various “build-up” methods.

The first normalization method entails calculating averages of yields to maturity on long-term government securities over various periods. This method’s implied assumption is that government bond yields revert to the mean. In Exhibit 7, the solid blue line is the spot yield on a 20-year U.S. government bond (December 2007–January 2016), whereas the dashed black line shows a 3.7% average monthly yield of the 20-year U.S. government bond over the previous 10 years ending on January 2016 (at the end of December 2015, the long-term average would still be 3.7%).[50] Government bond spot yields at the end of December 2015, and even more so at the end of January 2016, were lower than the monthly average over the last 10 years. Taking the average over the last 10 years is a simple way of “normalizing” the risk-free rate. An issue with using historical averages, though, is selecting an appropriate comparison period that can be used as a reasonable proxy for the future.

[49] “The Budget and Economic Outlook: 2016 to 2026”, released January 25, 2016. Again, using a maturity premium of 40 basis points would imply a 20-year yield of 3.9% in 2017 and a long-term 20-year yield of 4.5% starting in 2019. For more details on this report, visit: https://www.cbo.gov/sites/default/files/114th-congress-2015-2016/reports/51129-2016Outlook_OneCol-2.pdf.

[50] Source of underlying data: 20-year U.S. government bond series. Board of Governors of the Federal serve System website at: http:// www.federalreserve.gov/releases/h15/data.htm.

Exhibit 7: Spot and Average Yields on 20-year U.S. Government
December 2007–January 2016



The second normalization method entails using a simple build-up method, where the components of the risk-free rate are estimated and then added together. Conceptually, the risk-free rate can be (loosely) illustrated as the return on the following two components:[51]

Risk-Free Rate = Real Rate + Expected Inflation

Some academic studies have suggested the long-term "real" risk-free rate to be somewhere in the range of 1.2% to 2.0% based on the study of inflation swap rates and/or yields on long-term U.S. Treasury Inflation Protected Securities (TIPS).[52,53,54,55]

The second component, *expected inflation*, can also be estimated in a number of ways. Monetary policymakers and academics have been monitoring several measures of market expectations of future inflation. One method of estimating long-term inflation is to take the difference between the yield on a 20-year U.S. government bond yield and the yield of a 20-year U.S. TIPS. This is also known as the "breakeven inflation".[56] This calculation is shown in Exhibit 8 over the time period July 2004–January 2016.[57] Over this period, the average monthly breakeven long-term inflation estimate using this method was 2.3% (3.8% government bond yield – 1.5% TIPS). As of December 31, 2015, the average monthly breakeven long-term inflation estimate was also 2.3%.

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[51] This is a simplified version of the "Fisher equation", named after Irving Fisher. Fisher's "*The Theory of Interest*" was first published by Macmillan (New York), in 1930.

[52] TIPS are marketable securities whose principal is adjusted relative to changes in the Consumer Price Index (CPI).

[53] Haubrich, Joseph, George Pennacchi, and Peter Ritchken, "Inflation Expectations, Real Rates, and Risk Premia: Evidence from Inflation Swaps," *Review of Financial Studies* Vol. 25 (5) (2012): 1588-1629. The results of the authors' work is updated on a monthly basis and published in the Federal Reserve Bank of Cleveland's website. The 'Inflation Expectations' monthly series published in the 'Inflation Central' section of the website, contains an expected 10-year Real Risk Premia (as predicted by the model), which would be a proxy for the maturity premium of the 10-year real yield over the short-term real risk-free rate. For example, in December 2015, this expected 10-year Real Risk Premia was 1.2%. The 'Inflation Central' is located here: https://www.clevelandfed.org/en/our-research/inflation-central.aspx.

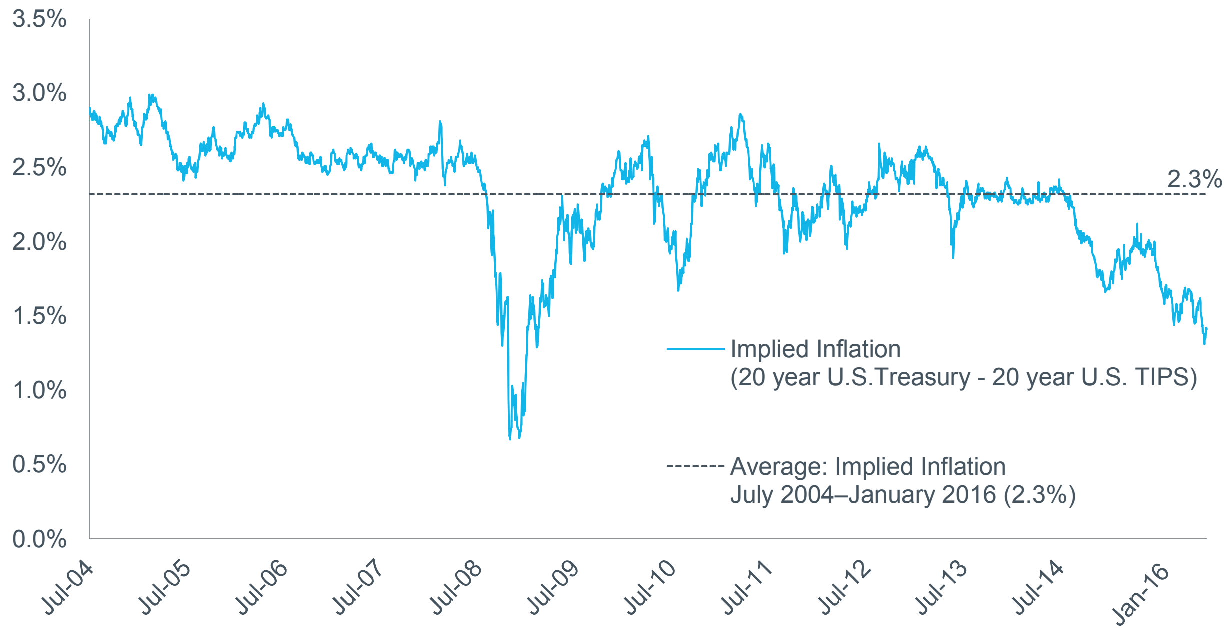
[54] Andrew Ang and Geert Bekaert "The Term Structure of Real Rates and Expected Inflation," *The Journal of Finance*, Vol. LXIII (2) (April 2008).

[55] Olesya V Grishchenko and Jing-zhi Huang "Inflation Risk Premium: Evidence From the TIPS Market," *The Journal of Fixed Income*, Vol. 22 (4) (2013): 5-30.

[56] Breakeven inflation is based on the differential between nominal and TIPS yields with equivalent maturity. However, several studies have documented that the breakeven inflation has not been a good predictor for inflation expectations. The differential between nominal and real rates is not only complicated by a liquidity premium, but also by the potential presence of the inflation risk premium, with both of these premiums varying through time. For a more detailed list of academic studies documenting the magnitude of the liquidity premium and the inflation risk premium, refer back to Chapter 7 of Shannon P. Pratt and Roger J. Grabowski, *Cost of Capital: Applications and Examples*, 5th ed. (Hoboken, NJ: John Wiley & Sons, 2014).

[57] Source of underlying data: 20-year U.S. government bond series and 20-year TIPS series, Board of Governors of the Federal Reserve System website at:
http://www.federalreserve.gov/releases/h15/data.htm. Calculated by Duff & Phelps LLC.

Exhibit 8: Breakeven Long-Term Inflation Estimate (20 year Government Bond Yield – 20 year TIPS Yield)
July 2004–January 2016



Additionally, in the U.S., there are a number of well-established surveys providing consensus estimates for expected inflation. One academic study has examined various methods for forecasting inflation over the period 1952–2004 and found that surveys significantly outperform other forecasting methods.[58] Exhibit 9 outlines some of the most prominent surveys in this area.[59] Altogether, the year-end 2015 estimates of longer-term inflation range from 1.8% to 2.6%.

[58] Ang, A., G. Bekaert, and M. Wei. "Do macro variables, asset markets, or surveys forecast inflation better?" *Journal of Monetary Economics*. 54, 1163-1212.
[59] Sources of underlying data: "The Livingston Survey: December 2015," Federal Reserve Bank of Philadelphia (December 10, 2015); "Survey of Professional Forecasters: Fourth Quarter 2015," Federal Reserve Bank of Philadelphia (November 13, 2015); *Blue Chip Financial Forecasts* Vol. 34 (12) (December 1, 2015); Federal Reserve Bank of Cleveland (estimates as of December 2015); Bloomberg.

Exhibit 9: Long-term Expected Inflation Estimates Year-end 2015 (approx.)

Source	Estimate (%)
Livingston Survey (Federal Reserve Bank of Philadelphia)	2.3
Survey of Professional Forecasters (Federal Reserve Bank of Philadelphia)	2.2
Cleveland Federal Reserve	1.8
Blue Chip Financial Forecasts	2.3
University of Michigan Survey 5-10 Year Ahead Inflation Expectations	2.6
Range of Expected Inflation Forecasts	1.8% – 2.6%

Adding the estimated ranges for the "real" risk-free rate and longer-term inflation together produces an estimated normalized risk-free rate range of 3.0% to 4.6%, with a midpoint of 3.8% (or 4.0%, if rounding to the nearest 50 basis points).

Range of Estimated Long-term Real Rate	1.2% to 2.0%
Range of Estimated Expected Inflation Forecasts	1.8% to 2.6%
Range of Estimated Long-term Normalized Risk-free Rate	3.0% to 4.6%
Midpoint	3.8%

Spot Yield or Normalized Yield?

Should the valuation analyst use the current market yield on risk-free U.S. government bonds (e.g., "spot" yield equal to 2.7% at December 31, 2015 or 2.4% at January 31, 2016) or use a "normalized" risk-free yield when estimating the cost of equity capital?

As stated earlier, in most circumstances we would prefer to use the "spot" yield on U.S. government bonds available in the market as a proxy for the U.S. risk-free rate. However, during times of flight to quality and/or high levels of central bank intervention, those lower observed yields imply a lower cost of capital (all other factors held the same) – just the opposite of what one would expect in times of relative economic distress – so a "normalization" adjustment may be considered appropriate. By "normalization" we mean estimating a rate that more likely reflects the sustainable average return of long-term risk-free rates. *If spot yield-to-maturity were used at these times, without any other adjustments, one would arrive at an overall discount rate that is likely inappropriately low vis-à-vis the risks currently facing investors*. Exhibit 10 shows the potential problems of simply using the spot yield-to-maturity on 20-year U.S. government bonds in conjunction with unadjusted U.S. historical equity risk premia.[60] Data is displayed for year-end 2007 through year-end 2015, as well as end of January 2016. For example, in December 2008, at the height of the Financial Crisis (when risks were arguably at all-time highs), using the 1926–2008 historical ERP of 6.5% together with the spot 20-year yield of 3.0% would result in a base cost of equity capital of 9.5%. In contrast, the base cost of equity would be 11.6% (4.5% plus 7.1%) at year-end 2007, implying that risks were actually higher at the end of 2007 than at the end of 2008. From both a theoretical and practical standpoint, the reality is that investors likely perceived risks to be much higher in December 2008, relative to the December 2007. This demonstrates that a mechanical application of the data may result in nonsensical results.[61]

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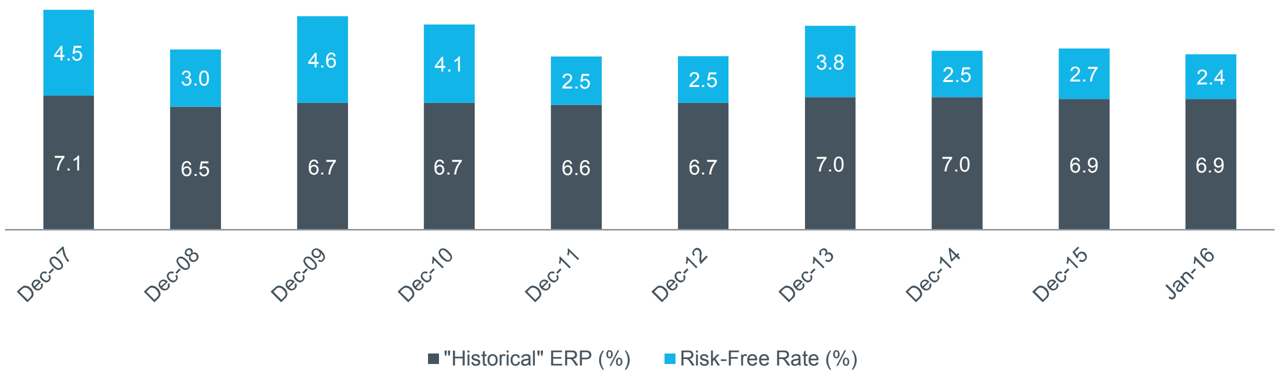
[60] Source of underlying data: Morningstar *Direct* database. Used with permission. Risk-free rate data series used: Long-term Gov't Bonds (IA SBBI US LT Govt YLD USD). All rights reserved. Calculations performed by Duff & Phelps LLC

[61] More detailed information on historical and forward-looking ERPs can be found later in this report.

Exhibit 10: Spot 20-year U.S. Treasury Yield in Conjunction with Unadjusted “Historical” Equity Risk Premium



Adjustments to the ERP or to the risk-free rate are, in principle, a response to the same underlying concerns and should result in broadly similar costs of capital. Adjusting the risk-free rate in conjunction with the ERP is only one of the alternatives available when estimating the cost of equity capital.

For example, one could use a spot yield for the risk-free rate, but *increase* the ERP or other adjustment to account for higher (systematic) risk. If the valuation analyst chooses to use the spot yield to estimate the cost of capital during periods when those yields are less than “normal,” the valuation analyst must use an estimated ERP that is *matched* to (or implied by) those *below-normal* yields. However we note that the most commonly used data sources for ERP estimates are long-term series measured when interest rates were largely not subject to such market intervention. Using those data series with an abnormally low spot yield creates a mismatch.

Alternatively, if the valuation analyst chooses to use a normalized risk-free rate in estimating the cost of capital, the valuation analyst must again use an estimated ERP that is *matched* to those *normalized* yields. Normalizing the risk-free rate is likely a more direct (and more easily implemented) analysis than adjusting the ERP due to a *temporary* reduction in the yields on risk-free securities, while *longer-term* trends may be more appropriately reflected in the ERP.

4.0%

The Duff & Phelps concluded normalized risk-free rate, as of January 31, 2016

We examined interest rates for the months since the Financial Crisis began. We also estimated a "normalized" yield each month using trailing averages and a build-up model. Considering longer-term averages of Treasury bond yields, and the build-up framework outlined above, Duff & Phelps has currently concluded on a 4.0% "normalized" risk free rate in developing its U.S. ERP (as compared to the 2.4% "spot rate" as of January 31, 2016). The 4.0% normalized risk-free rate should be used in conjunction with the 5.5% ERP recommendation outlined herein, implying a 9.5% (4.0% + 5.5%) base cost of equity capital for the U.S. as of January 31, 2016 and thereafter (until further guidance is issued) .

Exhibit 11 (in Section 4 of this report) displays the month by month spot yields on 20-year U.S. government bonds and the matching "normalized" yields (as suggested by Duff & Phelps) for months in which the normalized yields are greater than the corresponding spot yields. The months in which we believe a valuation analyst should consider using a normalized risk-free rate (or at least consider whether adjustments are warranted) are highlighted in bold and the "normalized" yields are shown in these months.

Section 04

Basis for U.S. ERP Recommendation as of January 31, 2016

Basis for U.S. Recommended ERP as of January 31, 2016

Unconditional ERP

ERP is a forward-looking concept. It is an expectation as of the valuation date for which no market quotes are directly observable. While an analyst can observe premiums realized over time by referring to historical data (i.e., realized return approach or ex post approach), such realized premium data do not represent the ERP expected in prior periods, nor do they represent the current ERP estimate. Rather, realized premiums represent, at best, only a sample from prior periods of what may have then been the expected ERP.

To the extent that realized premiums on the average equate to expected premiums in prior periods, such samples may be representative of current expectations. But to the extent that prior events that are not expected to recur caused realized returns to differ from prior expectations, such samples should be adjusted to remove the effects of these nonrecurring events. Such adjustments are needed to improve the predictive power of the sample.

Alternatively, the analyst can derive forward-looking estimates for the ERP from sources such as: (i) data on the underlying expectations of growth in corporate earnings and dividends; (ii) projections of specific analysts as to dividends and future stock prices; or (iii) surveys (an ex-ante approach). The goal of these approaches is to estimate the true expected ERP as of the valuation date.

Duff & Phelps recognizes that making any ERP estimate requires a great degree of judgment. In arriving at our recommended ERP, we weigh both economic and financial markets evidence. We choose to change our recommendations when the preponderance of evidence indicates a change is justified. We try to avoid making a change in one month to only find the evidence reversing itself the following month.

As indicated in Section 2 “Overview of Duff & Phelps ERP Methodology”, based on the analysis of academic and financial literature and various empirical studies, we have concluded that a reasonable long-term estimate of the normal or unconditional U.S. ERP is in the range of 3.5% to 6.0%.

From 5.0% to 5.5%

The change in the Duff & Phelps recommended U.S. Equity Risk Premium effective January 31, 2016

Conditional ERP

As previously stated, based on recent economic and financial market conditions (further described below), we are updating our estimated *conditional* ERP as of January 31, 2016. Specifically, Duff & Phelps is increasing its recommended U.S. ERP from 5.0% to 5.5% (while maintaining a *normalized* risk-free rate of 4.0%) when developing discount rates as of January 31, 2016 and thereafter, until further guidance is issued.

Exhibit 11 displays the Duff & Phelps U.S. ERP recommendations issued since 2008 until the present, along with an indication of whether spot yields on 20-year U.S. government bonds or "normalized" yields (as suggested by Duff & Phelps) were used. In months in which we believe a valuation analyst should consider using a normalized risk-free rate (or at least consider whether adjustments are warranted), we show the "normalized" yields that match the Duff & Phelps recommended U.S. ERP.

Exhibit 11: Duff & Phelps Recommended U.S. ERP and Corresponding Risk Free Rates January 2008−Present

	Duff & Phelps Recommended ERP	*Risk Free Rate*
Change in ERP Guidance (current guidance) ✓ January 31, 2015 − UNTIL FURTHER NOTICE	5.5%	4.0% Normalized 20-year Treasury yield *
Year-end 2015 Guidance December 31, 2015	5.0%	4.0% Normalized 20-year Treasury yield *
Change in ERP Guidance February 28, 2013 − January 30, 2016	5.0%	4.0% Normalized 20-year Treasury yield *
Change in ERP Guidance January 15, 2012 − February 27, 2013	5.5%	4.0% Normalized 20-year Treasury yield *
Change in ERP Guidance September 30, 2011 − January 14, 2012	6.0%	4.0% Normalized 20-year Treasury yield *
July 1, 2011 − September 29, 2011	5.5%	4.0% Normalized 20-year Treasury yield *
June 1, 2011 − June 30, 2011	5.5%	Spot 20-year Treasury Yield
May 1, 2011 − May 31, 2011	5.5%	4.0% Normalized 20-year Treasury yield *
December 1, 2010 − April 30, 2011	5.5%	Spot 20-year Treasury Yield
June 1, 2010 − November 30, 2010	5.5%	4.0% Normalized 20-year Treasury yield *
Change in ERP Guidance December 1, 2009 − May 31, 2010	5.5%	Spot 20-year Treasury Yield
June 1, 2009 − November 30, 2009	6.0%	Spot 20-year Treasury Yield
November 1, 2008 − May 31, 2009	6.0%	4.5% Normalized 20-year Treasury yield *
Change in ERP Guidance October 27, 2008 − October 31, 2008	6.0%	Spot 20-year Treasury Yield
January 1, 2008 − October 26, 2008	5.0%	Spot 20-year Treasury Yield

* Normalized in this context means that in months where the risk-free rate is deemed to be abnormally low, a proxy for a longer-term sustainable risk-free rate is used. To ensure the most recent ERP recommendation (and associated risk-free rate) is used, visit: www.duffandphelps.com/costofcapital.

To Be Clear:

December 31, 2015 (i.e., "year-end") Valuations: Duff & Phelps recommends a 5.0% U.S. ERP, matched with a normalized yield on 20-year U.S. government bonds equal to 4.0%, implying a 9.0% base cost of equity capital in the United States as of December 31, 2015.

January 31, 2016 Valuations: Duff & Phelps recommend a 5.5% U.S. ERP, matched with a normalized yield on 20-year U.S. government bonds equal to 4.0%, implying a 9.5% base cost of equity capital in the United States as of January 31, 2016 (and thereafter, until further notice).

Basis for Duff & Phelps Recommended U.S. ERP[62]

In estimating the conditional ERP, valuation analysts cannot simply use the long-term historical ERP, without further analysis. A better alternative would be to examine approaches that are sensitive to the current economic conditions.

As previously discussed, Duff & Phelps employs a multi-faceted analysis to estimate the conditional ERP that takes into account a broad range of economic information and multiple ERP estimation methodologies to arrive at its recommendation.[63]

First, a reasonable range of normal or unconditional ERP is established.

Second, based on current economic conditions, Duff & Phelps estimates where in the range the true ERP likely lies (top, bottom, or middle) by examining the current state of the economy (both by examining the level of stock indices as a forward indicator and examining economic forecasts), as well as the implied equity volatility and corporate spreads as indicators of perceived risk.

For example, since December 31, 2014, while the evidence was somewhat mixed, on balance we saw indications that equity risk in financial markets had stayed relatively constant through the end of 2015, when estimated against a normalized risk-free rate of 4.0%. Exhibit 12-A summarizes the primary economic and financial market indicators we analyzed at December 31, 2015 and how they have moved since December 31, 2014, with the corresponding relative impact on ERP indications:

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[62] This discussion was extracted from Chapter 3 of the Duff & Phelps *2016 Valuation Handbook – Guide to Cost of Capital* (Hoboken, NJ: John Wiley & Sons, 2016). The discussion in this section was based on information available at the time of writing (through February 23, 2016). Events and market conditions may have changed since then relative to when this report is issued.

[63] To ensure you are always using the most recent ERP recommendation, visit: www.duffandphelps.com/costofcapital.

Exhibit 12-A: Economic and Financial Market Indicators Considered in Duff & Phelps' U.S. ERP Recommendation *as of December 31, 2015*

Factor	Change	Effect on ERP
U.S. Equity Markets	↔	↔
Implied Equity Volatility	↔	↔
Corporate Spreads	↑	↑
Historical Real GDP Growth and Forecasts	↔	↔
Unemployment Environment	↓	↓
Consumer and Business Sentiment	↔	↔
Sovereign Credit Ratings	↔	↔
Damodaran Implied ERP Model	↑	↑
Default Spread Model	↑	↑

Recent economic indicators point to a positive, yet below-pace, real growth for the U.S. economy. The economy has been expanding at a modest rate, but generally better than other major developed economies, and with the risks of a recession seemingly tempered. The employment situation is reaching a level of stability, with the U.S. economy reaching close to full employment. Consumer confidence and business sentiment are generally stable, with the former still above its long-term average.

On the other hand, inflation has been persistently below the Fed's target of 2.0%. The sharp decline in oil prices since 2014 has put additional pressure in an already very low inflation environment.

Concerns about a slowing global economy and deflationary pressures have troubled investors in 2015. Tumbling oil and other commodity prices have reinforced investor anxiety over stagnant growth in the Eurozone and Japan, as well as a deceleration in several emerging-market countries, with a particular focus on China (considered by many analysts as the engine of growth for the global economy). Global financial markets reacted negatively to these trends in August and September of 2015, but settled down towards year-end. As a result, the Fed saw sufficient support to raise its benchmark interest rate in December 2015, the first time since the beginning of the 2008 global financial crisis.

Since early 2016, however, broad equity indices (e.g., the S&P 500) across the globe have suffered significant losses, market volatility has spiked, and credit spreads of U.S. high-yield over U.S. investment grade corporate bonds continued to widen substantially (now affecting companies outside the oil and mining sectors). This has led global investors to seek safe haven investments, such as securities issued by the U.S., Germany, and United Kingdom governments, to name a few, causing sharp declines in government bond yields for these countries. Financial markets are now attaching a lower probability of further interest rate increases by the Fed in the near term.

We show in Exhibit 12-B the primary economic and financial market indicators as of January 31, 2016 and how they have moved since year-end 2014, with the corresponding relative impact on ERP indications.

Exhibit 12-B: Economic and Financial Market Indicators Considered in Duff & Phelps' ERP Recommendation *as of January 31, 2016*

Factor	Change	Effect on ERP
U.S. Equity Markets	↓	↑
Implied Equity Volatility	↑	↑
Corporate Spreads	↑	↑
Historical Real GDP Growth and Forecasts	↔	↔
Unemployment Environment	↓	↓
Consumer and Business Sentiment	↔	↔
Sovereign Credit Ratings	↔	↔
Damodaran Implied ERP Model	↑	↑
Default Spread Model	↑	↑

Finally, we examine other indicators that may provide a more quantitative view of where we are within the range of reasonable long-term estimates for the U.S. ERP.

Duff & Phelps currently uses several models as corroborating evidence. We reviewed these indicators both at year-end 2015 and at the end of January 2016.

- **Damodaran Implied ERP Model** − Professor Aswath Damodaran calculates implied ERP estimates for the S&P 500 and publishes his estimates on his website. Prof. Damodaran estimates an implied ERP by first solving for the discount rate that equates the current S&P 500 index level with his estimates of cash distributions (dividends and stock buybacks) in future years. He then subtracts the current yield on 10-year U.S. government bonds. Duff & Phelps then converts his estimate to an arithmetic average equivalent measured against the 20-year U.S. government bond rate.

  Prof. Damodaran has recently added new capabilities to his implied equity risk premium calculator. The new features introduced last year allow the user to select a variety of base projected cash flow yields, as a well as several expected growth rate choices for the following five years in the forecast. Each option for cash flow yields is independent of the growth rate assumptions, which means that the user can select up to 35 different combinations to estimate an implied ERP. More recently, Prof. Damodaran added a new feature that allows the terminal year's projected cash flows to be adjusted to what he considers a more sustainable payout ratio. This sustainable payout is computed using the long-term growth rate (g) and the trailing 12-month return on equity (ROE), as follows: Sustainable Payout = 1 – g/ROE. If the user selects this option, the payout ratio over the next (projected) five years is based on a linear interpolation between today's payout ratio and the Sustainable Payout. Otherwise, the terminal year payout ratio will be the same as today's value throughout the entire forecast.

  Exhibit 13 shows the current options that a user can select to arrive at an implied ERP indication. Each of these combinations can then be adjusted for a sustainable payout, if the user so decides.[64]

[64] Source of underlying data: Downloadable dataset entitled "Spreadsheet to compute ERP for current month". To obtain a copy, visit: http://people.stern.nyu.edu/adamodar/.

Exhibit 13: Professor Damodaran's Implied Equity Risk Premium Calculator Cash Flow Yield (Dividends + Buybacks) and Growth Rate Options

S&P 500 Cash Flow Yield (Dividends + Buybacks)	S&P Earnings Growth Rates for Years 1 through 5 in the Projections	Adjustment for Sustainable Payout
Trailing 12 months Dividend + Buyback Yield	Historical Growth Rate for the last 10 years	Adjust Cash Flow Yield for Sustainable Payout
Average Dividend + Buyback Yield for the last 10 years	Bottom-up Forecasted Growth Rate for next 5 years	Do Not Adjust Cash Flow Yield for Sustainable Payout
Average Dividend + Buyback Yield for the last 5 years	Top-Down Forecasted Growth Rate for next 5 years	
Average Payout for the last 10 years	Fundamental Growth Rate (based on Current ROE)	
Average Payout for the last 5 years	Fundamental Growth Rate (based on 10-Year Average ROE)	
Average Payout using S&P 500 Normalized Earnings		
Trailing 12 months Dividend + Buyback Yield, Net of Stock Issuance		

Note: ROE = Return on Equity

Based on Prof. Damodaran's estimates of the trailing 12-month cash flow yield (dividends plus buybacks) of S&P 500 constituents – as published on the home page of his website – his implied ERP (converted into an arithmetic average equivalent) was approximately 7.16% measured against an abnormally low 20-year U.S. government bond yield (2.67%), as of December 31, 2015.[65] The equivalent normalized implied ERP estimate was 5.83% measured against a normalized 20-year U.S. government bond yield (4.0%), which represents an increase of 44 basis points relative to the prior year's indication.[66] Testing the various available options outlined in Exhibit 13 – but not adjusting for a Sustainable Payout in the terminal year – we obtained a range of indications for a normalized arithmetic average implied ERP estimate between 3.77% and 6.42% (once again, measured against a normalized 20-year U.S. government bond yield of 4.0%), representing an increase in the range observed last year. Alternatively, if projected cash flows were adjusted for a Sustainable Payout, the implied ERP indications would narrow to a range between 4.45% and 5.33%.

Performing these same steps as of January 31, 2016 would result in increased ERP indications, if computed against spot yields, but similar ones when using a normalized risk-free rate. For example, the implied arithmetic average ERP measured against the spot 20-year U.S. government bond yield (2.36%) was 7.49%, using a trailing 12-month cash flow yield.[67] Against a normalized 20-year U.S. government bond yield (4.0%), this implied ERP would be 5.85% as of January 31, 2016.[68] Similarly, we obtained a range of normalized arithmetic average implied ERP estimates between 3.71% and 6.48% (unadjusted for Sustainable Payout and measured against a normalized 20-year U.S. government bond yield of 4.0%).

[65] Damodaran's implied rate of return (based on the actual 10-year yield) on the S&P 500 = 8.39% as of January 1, 2016, minus 2.67% actual rate on 20-year U.S. government bonds plus an adjustment to equate the geometric average ERP to its arithmetic equivalent. The result reflects conversion of the implied ERP to an arithmetic average equivalent.

[66] Damodaran's implied rate of return (based on the actual 10-year yield) on the S&P 500 = 8.39% as of January 1, 2016 minus 4.00% normalized rate on 20-year U.S. government bonds plus an adjustment to equate the geometric average ERP to its arithmetic equivalent. The result reflects conversion of the implied ERP to an arithmetic average equivalent.

[67] Damodaran's implied rate of return (based on the actual 10-year yield) on the S&P 500 = 8.41% as of February 1, 2016, minus 2.36% actual rate on 20-year U.S. government bonds plus an adjustment to equate the geometric average ERP to its arithmetic equivalent. The result reflects conversion of the implied ERP to an arithmetic average equivalent.

[68] Damodaran's implied rate of return (based on the actual 10-year yield) on the S&P 500 = 8.41% as of February 1, 2016 minus 4.00% normalized rate on 20-year U.S. government bonds plus an adjustment to equate the geometric average ERP to its arithmetic equivalent. The result reflects conversion of the implied ERP to an arithmetic average equivalent.

[**Note**: Appendix A summarizes the U.S. ERP implied by the Damodaran model since December 31, 2008, as converted by Duff & Phelps into an arithmetic average equivalent against normalized 20-year U.S. government bonds.]

- **Default Spread Model (DSM)** – The Default Spread Model is based on the premise that the long term average ERP (the unconditional ERP) is constant and deviations from that average over an economic cycle can be measured by reference to deviations from the long term average of the default spread (Baa - Aaa).[69]

  At the end of December 2015 and January 2016, the conditional ERP calculated using the DSM model was 5.51% and 5.65% respectively. For perspective, the last time this model resulted in an implied ERP in excess of 5.5% was back in August 2012. This model notably removes the risk-free rate itself as an input in the estimation of ERP. However, the ERP estimate resulting from the DSM is still interpreted as an estimate of the relative return of stocks in excess of risk-free securities.

[**Note:** Appendix B summarizes the conditional U.S. ERP (CERP) implied by the Default Spread Model since December 31, 2008.]

- **Hassett Implied ERP (Hassett)** – Stephen Hassett has developed a model for estimating the implied ERP, as well as the estimated S&P 500 index level, based on the current yield on long-term U.S. government bonds and a risk premium factor (RPF).[70] The RPF is the empirically derived relationship between the risk-free rate, S&P 500 earnings, real interest rates, and real GDP growth to the S&P 500 index over time. The RPF appears to change only infrequently. The model can be used monthly to estimate the S&P 500 index level and the conditional ERP based on the current level of interest rates.[71]

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[69] The Default Spread Model presented herein is based on Jagannathan, Ravi, and Wang, Zhenyu," The Conditional CAPM and the Cross -Section of Expected Returns," *The Journal of Finance*, Volume 51, Issue 1, March 1996: 3-53. See also Elton, Edwin J. and Gruber, Martin J., Agrawal, Deepak, and Mann, Christopher "Is There a Risk Premium in Corporate bonds?", Working Paper, http://pages.stern.nyu.edu/~eelton/working_papers/corp%20bonds/Is%20there%20a%20risk%20premium%20in%20corporate%20bonds.pdf. Duff & Phelps uses (as did Jagannathan, Ravi, and Wang) the spread of high-grade corporates against lesser grade corporates. Corporate bond series used in analysis herein: Barclays US Corp Baa Long Yld USD (Yield) and Barclays US Corp Aaa Long Yld USD (Yield); Source: Morningstar *Direct*.

[70] Stephen D. Hassett, ''The RPF Model for Calculating the Equity Risk Premium and Explaining the Value of the S&P with Two Variables,'' *Journal of Applied Corporate Finance* 22, 2 (Spring 2010): 118–130.

[71] For a more detailed description of Hassett's Risk Premium Factor model see Pratt and Grabowski, op.cit., Chapter 8A, "Deriving ERP Estimates": 167-168".

Hassett's analysis uses the spot 10-year risk-free rate for the period from January 2008 through July 2011; thereafter, his analysis uses a normalized yield on U.S. Treasuries of 4.5% (2.0% real risk-free rate plus 2.5% inflation).[72] Using a normalized 4.5% risk-free rate at both December 2015 and January 2016, the S&P 500 index appeared to be slightly overvalued based on the Hassett model's predictions. Alternatively, based on the S&P 500 index level at the end of December 2015, the implied risk-free rate commensurate with the index closing price was 3.90%. At the end of January 2016, the implied risk-free rate was slightly up at 4.08%. Both of these indications for the risk-free rate are very close to the Duff & Phelps concluded normalized risk-free rate of 4.0% at both dates.

While these additional models may be useful in suggesting the direction of changes in the conditional ERP, they are, like all methods of estimating the ERP, imperfect. The Damodaran Implied ERP Model, the Default Spread Model, and the Hassett Implied ERP Model all utilize assumptions that are subjective in nature. For example, the Damodaran Implied ERP Model assumes a long-term growth rate for dividends and buybacks that is largely a matter of judgment. Likewise, in the default spread model, the changes in spread are applied to a "benchmark" ERP estimate; the choice of that benchmark ERP is largely a matter of judgment.

Again, the inherent "imperfection" of any single ERP estimation model is precisely why Duff & Phelps takes into account a broad range of economic information and multiple ERP estimation methodologies to arrive at our conditional ERP recommendation.

Taking these factors together, we find support for increasing our ERP recommendation relative to our previous recommendation

TO BE CLEAR:

5.5%

The Duff & Phelps U.S. Equity Risk Premium Recommendation effective January 31, 2016

- Many valuations are done at year-end. The Duff & Phelps U.S. ERP recommendation for use with December 31, 2015 valuations is 5.0%, matched with a normalized risk-free rate of 4.0%. This implies a 9.0% (4.0% + 5.0%) "base" U.S. cost of equity capital estimate as of December 31, 2015.

- The Duff & Phelps U.S. ERP recommendation as of January 31, 2016 (and thereafter, until further notice) is 5.5%, matched with a normalized risk-free rate of 4.0%. This implies a 9.5% (4.0% + 5.5%) "base" U.S. cost of equity capital estimate as of January 31, 2016.

[72] "Dissecting S&P 500 2015 Performance Using The RPF Model" by Steve Hassett, Retrieved from: http://seekingalpha.com/article/3811186-dissecting-s-and-p-500-2015-performance-using-rpf-model.

Section 05

Conclusion

Conclusion

Duff & Phelps U.S. Equity Risk Premium and Risk-Free Rate Guidance as of January 31, 2016

- Equity Risk Premium: Increase from 5.0% to 5.5%
- Risk-Free Rate: 4.0% (normalized)
- Base U.S. Cost of Equity Capital: 9.5% (4.0% + 5.5%)

Based on the foregoing, we find evidence to adjust our ERP recommendation upwards to 5.5% relative to our previous guidance issued on February 28, 2013, when the U.S. ERP was adjusted downward (from 5.5% to 5.0%). During 2015, we started seeing some signs of increased risk in financial markets. As further explained below, while the evidence was somewhat mixed as of December, 31, 2015, we can now see clear indications that equity risk in financial markets has increased significantly as of January 31, 2016. Exhibit 14 summarizes the factors considered in our U.S. ERP recommendation.[73]

Exhibit 14: Factors Considered in U.S. ERP Recommendation

Factor	Change	Effect on ERP
U.S. Equity Markets	↓	↑
Implied Equity Volatility	↑	↑
Corporate Spreads	↑	↑
Historical Real GDP Growth and Forecasts	↔	↔
Unemployment Environment	↓	↓
Consumer and Business Sentiment	↔	↔
Sovereign Credit Ratings	↔	↔
Damodaran Implied ERP Model	↑	↑
Default Spread Model	↑	↑

[73] Exhibit 14 is identical to the previous Exhibit 1 (see "Executive Summary") as well as to Exhibit 12-B, and is reproduced here for reader convenience. The factors listed in Exhibit 14 are the factors that were considered the most relevant at the end of January 2016. The factors that Duff & Phelps considers in its monthly review of its ERP recommendation can vary, depending on the economic situation at the time.

Recent economic indicators point to a positive, yet below-pace, real growth for the U.S. economy. The U.S. economy has been expanding at a modest rate, but generally better than other major developed economies, and with the risks of a recession seemingly tempered. The employment situation is reaching a level of stability, with the U.S. economy reaching close to full employment. Consumer confidence and business sentiment are generally stable, with the former still above its long-term average.

On the other hand, inflation has been persistently below the Federal Reserve Bank's (Fed) target of 2.0%. The sharp decline in oil prices since 2014 has put additional pressure in an already very low inflation environment. For perspective, the price of Brent crude oil was at $115/barrel in mid-June 2014; since then prices declined to $38/barrel at the end of 2015, a cumulative 67% decline in the space of a year and a half.

Concerns about a slowing global economy and deflationary pressures have troubled investors in 2015. Tumbling oil and other commodity prices have reinforced investor anxiety over stagnant growth in the Eurozone and Japan, as well as a deceleration in several emerging-market countries, with a particular focus on China (considered by many analysts as the engine of growth for the global economy). Global financial markets reacted negatively to these trends in August and September of 2015, but settled down towards year-end. Since the beginning of 2016, however, broad equity indices (e.g., the S&P 500) across the globe have suffered significant losses, market volatility has spiked, and credit spreads of U.S. high-yield bonds over U.S. investment grade corporate bonds continued to widen substantially (now affecting companies outside the oil and mining sectors).

This has led global investors to seek safe haven investments, such as securities issued by the U.S., Germany, and United Kingdom governments, to name a few, causing sharp declines in government bond yields for these countries. Despite the fact that in December 2015 the Fed decided to raise U.S. interest rates for the first time since the beginning of the 2008 global financial crisis, financial markets are now attaching a lower probability of further increases in the near term.

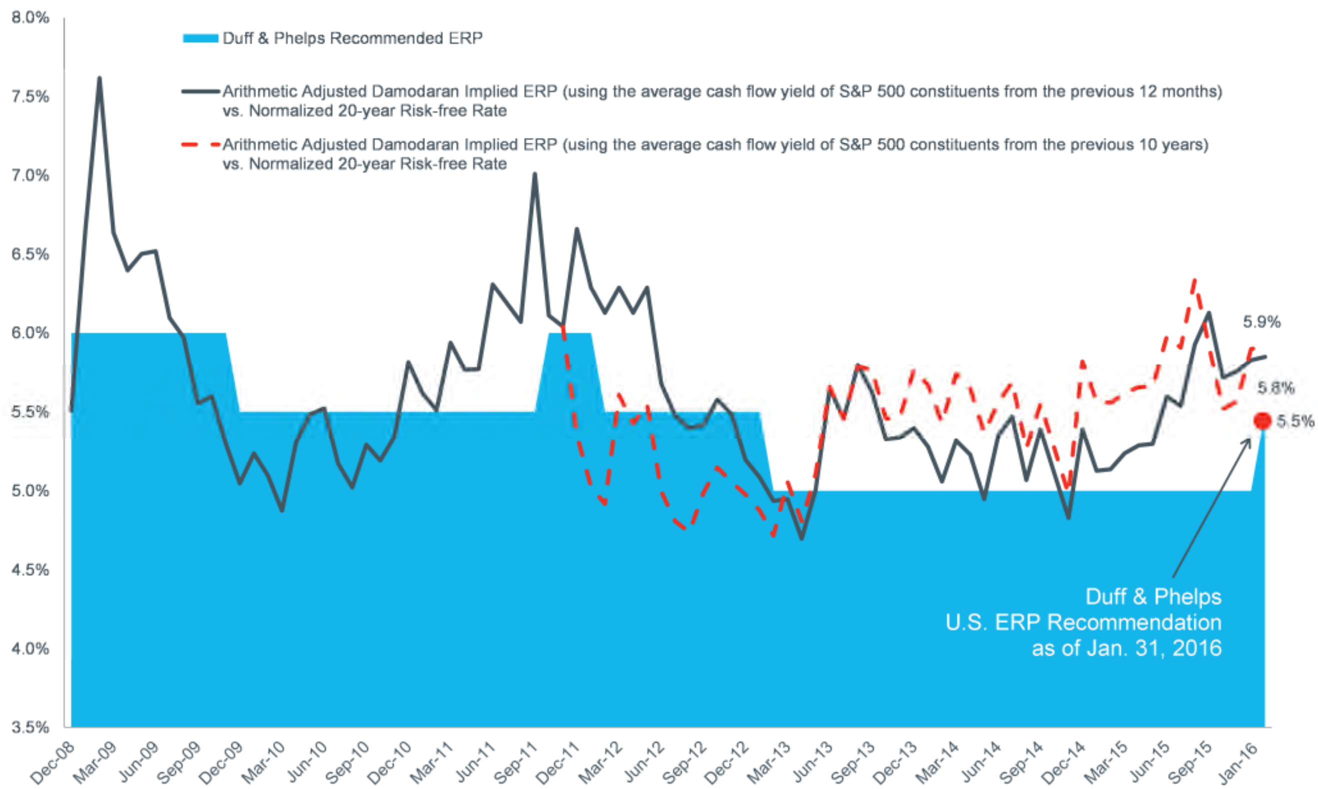
Duff & Phelps monitors two additional quantitative models as corroboration of the qualitative factors discussed above: 1) the Damodaran Implied ERP Model and (2) the Default Spread Model. Both of these models indicated a higher ERP at the end of January 2016 relative to our prior recommendation issued back February 2013.

Taken together, we found sufficient support for increasing our ERP recommendation relative to our previous recommendation. Accordingly, Duff & Phelps recommends a U.S. Equity Risk Premium of 5.5% when developing discount rates as of January 31, 2016 and thereafter, to be used in conjunction with a normalized risk-free rate of 4.0%.

Section 06

Appendices

Appendix A – Damodaran Implied ERP Model



Additional Indicators: The Damodaran Implied ERP Model

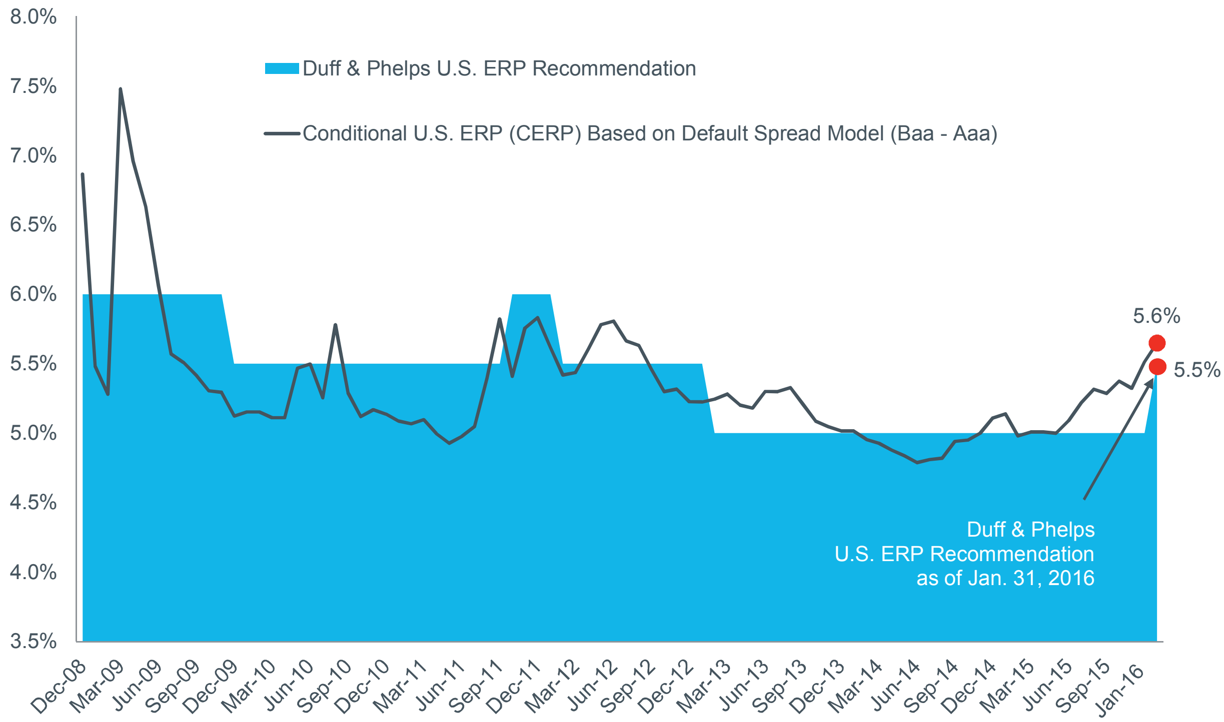
The graph illustrates the Damodaran Implied U.S. ERP model over the time period December 2008 through January 2016 (estimated using a "normalized" 20-year U.S. Treasury yield) as compared to the Duff & Phelps U.S. ERP recommendation.

- At the end of January 2016, the U.S. ERP implied by the Damodaran Model was 5.8% using the average cash flow yield of S&P 500 constituents from the *previous 12 months*, and a normalized 4.0% risk free rate.

- At the end of January 2016, the U.S. ERP implied by the Damodaran Model was 5.9% using the average cash flow yield of S&P 500 constituents from the *previous 10 years*, and a normalized 4.0% risk free rate.

Duff & Phelps regularly reviews fluctuations in global economic and financial conditions that warrant periodic reassessments of ERP. As of January 31, 2016, Duff & Phelps' U.S. ERP recommendation is 5.5%, used in conjunction with a 4.0% normalized risk-free rate.

Appendix B – Default Spread Model



Additional Indicators: The Default Spread Model

The graph illustrates the Default Spread Model used to estimate a conditional U.S. ERP (CERP) over the time period December 2008 through January 2016 as compared to the Duff & Phelps U.S. ERP recommendation. This model notably removes the risk-free rate itself as an *input* in the estimation of ERP. However, the ERP estimate resulting from the Default Spread Model is still interpreted as an estimate of the relative return of stocks *in excess* of risk-free securities.

- At the end of January 2016, the U.S. ERP implied by the Default Spread Model was 5.6%.

Duff & Phelps regularly reviews fluctuations in global economic and financial conditions that warrant periodic reassessments of ERP. As of January 31, 2016, Duff & Phelps' U.S. ERP recommendation is 5.5%, used in conjunction with a 4.0% normalized risk-free rate.

For more information, visit:
www.duffandphelps.com\costofcapital

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Kevin Madden
Analyst

WM-5 Commentary from Janus Capital, March 30, 2016.

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Zeno's Paradox

Investment Outlook from Bill Gross - April 2016

I once wrote that a good "bond manager" should metaphorically be composed of 1/3 mathematician, 1/3 economist and 1/3 horse trader. I still stand by that, although I would extend it now to the entire investment arena, especially after experiencing several years of "unconstrained" asset management. Surprisingly though, upon reflection, I find that personally I was never really an "A+ student" at any of the 3 but good enough at each to provide consistent long term alpha and above average profits for clients. In math, for instance, I was a 720 SAT guy but certainly nowhere near 800 status. In economics, I never got beyond Samuelson and an introductory MBA class at UCLA Anderson, but was self-educated enough to have forecast and ridden the secular bond bull market beginning in 1981, and fortunate enough – though "addled" – to have predicted the housing crisis, as well as named and described the "New Normal" that would follow. Horse trader? Well that's an even more subjective assessment but I can remember being a rather mediocre fraternity poker player. You could usually bluff me out of a big pot, and these days in the market I find myself turning right sometimes when I should be going left. Whatever. B+, A-, B is how I would grade myself but the returns and the relative alpha compared to contemporaries proved to be the real scorecard, and I'm happy with the result, acknowledging of course that some in the "classroom" I worked and work with at PIMCO and Janus earned Summa Cum Laude status and more themselves.

But back to the 1/3 math thing. It's there that I find the average lay and even many professional investors still thinking and managing assets at the grade school level. The childlike "teeter totter" principle, for instance which couldn't be simpler in its visualization of bond prices going up when interest rates go down, produces foggy-eyed reactions from a majority of non-professionals, and from a few supposed experts as well. And too, the concept of longer maturities inducing more risk for bond holders seems to stump many. Heaven forbid the introduction of the more refined concepts of duration and forward yield curves as well as the extension into stocks with the addition of an equity "risk premium" and how it might be calculated. "Forget about the math," many investors really seem to say – "let's stick to the old Will Rogers adage, 'If a stock is going to go up – buy it. If it ain't going up – don't buy it'! "

Well today's markets are markets that increasingly will be dominated by math, not Will Rogers. And negative interest rates are front and center. To explain, let me introduce a twister I first came across during one of my high school math classes known as Zeno's paradox. Zeno was an ancient Greek who posed the following conundrum: Imagine a walker heading towards a finish line 10 yards away but every step he took was half of the length of the step he took before. If so, even if he walked an infinite amount of steps he could never reach his destination. Mathematically correct but the real world resolution was that Zeno's walker and everything else that we experience moves forward in full step integers as opposed to fractions. It was a mathematical twist only.

But there is no "math only" twist to today's bond and investment markets. Negative interest rates are real but investors seem to think that they have a Zeno like quality that will allow them to make money. In Germany for instance, 5 year Bunds or OBL's as they are called, yield a negative 30 basis points. That produces a current price of 101.50 at a 0% coupon that guarantees, guarantees that an investor will get back 100 Euros 5 years from now for every 101.50 Euros she invests today. Why would a private investor (the ECB has a different logic) buy a 5 year OBL at a minus 30 basis points and lock in a guaranteed loss? Well credit and electronic money has its modern day disadvantages in that you can't withdraw billions of physical Euro Notes from the local bank, nor can banks withdraw some from the central bank. You have to buy something and that's the yield that's artificially being imposed. Besides, the purpose of it is to force the investor to buy something with a positive yield further out the maturity spectrum or better yet with a little or a lot of credit risk to get inflation and the economy's growth engine started again. Seemingly logical, but as I've pointed out in recent years – not working very well because zero and negative interest rates break down capitalistic business models related to banking, insurance, pension funds, and ultimately small savers. They can't earn anything!

Anyway, for those private investors that continue to hold 5 year OBL's and lock in a guaranteed loss 5 years from now, many of them are using a bit of Zeno's paradox to convince themselves that they will never reach the loss-certain finish line at maturity. They think that because 4 year OBL's yield even less (-40 basis points), the 5 year OBL's will actually go up in price (remember the teeter totter?) if 4 year rates stay the same over the next 12 months, and the ECB has sort of – sort of – promised that. Whatever it takes, you know. If so, the private investor will actually make a little money over the next year (10 basis points) and she can give herself a slap on the back for having eluded the ECB's negative interest rate trap!

Ah but Zeno's, Draghi's, Kuroda's, and even Yellen's paradox is actually just that – a paradox. Some investor has to cross the finish/maturity line even if yields are suppressed perpetually, which means that the "market" will actually lose money. Yet who cares about Zeno and a bunch of 5 year OBL investors? Well 30-40% of developed bond markets now have negative yields and 75% of Japanese JGB's do. Still who cares about them, just buy high yield bonds or even stocks to avoid Zeno's paradoxical trap. No! All financial assets are ultimately priced based upon the short term interest rate, which means that if an OBL investor loses money, then a stock investor will earn much, much less than historically assumed or perhaps might even lose money herself. Yields have been at 0% or negative for years now across most developed markets and to assume that high yield bond and equity risk premiums as well as P/E ratios have not adjusted to this Star Trek interest rate world is to believe in – well to believe in Zeno's paradox.

The reality is this. Central bank polices consisting of QE's and negative/artificially low interest rates must successfully reflate global economies or else. They are running out of time. To me, in the U.S. for instance, that means nominal GDP growth rates of 4-5% by 2017 – or else. They are now at 3.0%. In Euroland 2-3% - or else. In Japan 1-2% - or else. In China 5-6% - or else. Or else what? Or else markets and the capitalistic business models based upon them and priced for them will begin to go south. Capital gains and the expectations for future gains will become Giant Pandas – very rare and sort of inefficient at reproduction. I'm not saying this will happen. I'm saying that developed and emerging economies are flying at stall speed and they've got to bump up nominal GDP growth rates or else. Cross your fingers. Zeno's paradox was a mathematical twist only and the artificial/negative interest rate world created by central bankers has similar logic. The real market and the real economy await a different conclusion as losses from negative rates result in capital losses, not capital gains. Investors cannot make money when money yields nothing. Unless real growth/inflation commonly known as Nominal GDP can be raised to levels that allow central banks to normalize short term interest rates, then south instead of north is the logical direction for markets.

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Janus has been helping fixed income investors reach their financial goals for more than 25 years. Our team of investment experts is committed to delivering the stability our clients expect, with an unwavering focus on risk-adjusted returns and capital preservation. Today, we serve investors across a variety of markets by offering a diverse suite of fixed income strategies with highly complementary and distinctly separate investment approaches: a bottom-up, fundamental suite of strategies, and a top-down, global macro process.

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To Top

WM-6 Response to APSC 52.03, Docket 10-067-U, APSC 77.03 in this case.

OKLAHOMA GAS AND ELECTRIC COMPANY
Response to Arkansas Public Service Commission
Staff Data Request APSC-052
Docket No. 10-067-U

Date Requested: 1/19/2011 Date Required: 2/4/2011 Requested by: Rick Dunn

52.03 EEI Dues

Please provide for each year the Edison Electric Institute's "Schedule of Expenses by NARUC Category – For Core Dues Activities".

Response: Please see attachments **APSC 052.03_Att 1** and **APSC 052.03_Att 2.**

Response provided by: Alex Karanja
Response provided on: February 5, 2011
Contact & Phone No: Sheri Richard (405) 553-3747

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Edison Electric Institute
Schedule of Expenses
For Core Dues Activities
For the years Ended December 31, 2005 - 2009
(Unaudited)

Operating Expense Category	% of Dues				
	2005	2006	2007	2008	2009
Legislative Advocacy and Policy Research	26.4%	25.7%	16.2%	14.4%	21.9%
Public Relations	7.7%	8.8%	2.2%	2.0%	2.4%
Advertising	1.7%	1.3%	0.9%	2.3%	2.3%
Marketing	3.7%	3.9%	0.0%	0.0%	0.0%

701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
Telephone 202-508-5000

EDISON ELECTRIC INSTITUTE

June 10, 2010

Dear Committee Members:

We have completed the calculation of EEI's actual final expenditures relating to influencing legislation for calendar year 2009. A total of 21.9% of our regular dues was devoted to non-deductible activities in 2009. In addition, 34.2% of the assessments for the SFA for Industry Issues, 2.2% of the assessment for the SFA for Environment, 4.6% of the assessment for the Utility Solid Waste Activities Group (USWAG), and 97% of the assessment for the Water Advocacy Coalition (WAC) were devoted to non-deductible activities in 2009. These percentages may affect the extent to which your 2009 EEI dues and SFA payments qualify as a deductible business expense.

These actual figures differ from the earlier estimates contained in your 2009 dues invoice and our letter dated July 22, 2009. For your convenience, a chart with original and revised estimates for 2009 and 2010, as well as actual results for 2009, is provided below. The actual percentages for calendar year 2010 will be provided to you by mid-2011.

Summary of 2009 and 2008 Estimated, Revised and Actual Percentages

	Regular Activities	Separately Funded Activities (SFA)			
	Core Dues	Industry Issues	Environment	USWAG	WAC
2009					
Original Estimate on dues invoice	16.0%	35.0%	-	-	-
Revised Estimate – July 2009	16.0%	35.0%	4.0%	5.0%	100%
Actual/Final	**21.9%**	**34.2%**	**2.2%**	**4.6%**	**97%**
2010					
Original Estimate on dues invoice	16.0%	35.0%	-	-	-
Revised Estimate – July 2010	21.0%	35.0%	2.0%	5.0%	100%

Please do not hesitate to contact me or John Schlenker at (202) 508-5540 or jschlenker@eei.org if you have any questions.

Sincerely,

Patric D. O'Kelley

OKLAHOMA GAS AND ELECTRIC COMPANY
Response to Arkansas Public Service Commission
Staff Data Request APSC-077
Docket No. 16-052-U

Date Requested: 12/2/2016 Date Required: 12/19/2016 Requested by: Joy Brooks

77.03 Please provide for each year the Edison Electric Institute's "Schedule of Expenses by NARUC Category – For Core Dues Activities". See Data Request response from the last general rate case Docket No.10-067-U, (APSC 052).

Response*: Please see **APSC 077.03_Att**.

Response provided by: Morgan Hartman
Response provided on: December 19, 2016
Contact & Phone No: Jason Bailey (405) 553-3406

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

701 Pennsylvania Avenue, N.W. | Washington, D.C. 20004-2696 | 202.508.5000 | www.eei.org

Power by Association™

Edison Electric Institute

June 9, 2011

Dear Committee Members:

We have completed the calculation of EEI's actual final expenditures relating to influencing legislation for calendar year 2010. A total of 23.4% of our regular dues was devoted to non-deductible activities in 2010. In addition, 38.5% of the assessments for the SFA for Industry Issues, 4.3% of the assessment for the SFA for Environment, 3.8% of the assessment for the Utility Solid Waste Activities Group ("USWAG"), and 62.1% of the assessment for the Water Advocacy Coalition (WAC) were devoted to non-deductible activities in 2010. These percentages may affect the extent to which your 2010 EEI dues and SFA payments qualify as a deductible business expense.

These actual figures differ from the earlier estimates contained in your 2010 dues invoice and our letter dated June 10, 2010. For your convenience, a chart with original and revised estimates for 2010 and 2011, as well as actual results for 2010, is provided below. The actual percentages for calendar year 2011 will be provided to you by mid-2012.

Summary of 2010 and 2011 Estimated, Revised and Actual Percentages

	Regular Activities	Separately Funded Activities (SFA)			
	Core Dues	Industry Issues	Environment	USWAG	WAC
2010					
Original Estimate on dues invoice	16.0%	35.0%	2.0%	-	-
Revised Estimate – June 2010	21.0%	35.0%	2.0%	5.0%	100%
Actual/Final	**23.4%**	**38.5%**	**4.3%**	**3.8%**	**62.1%**
2011					
Original Estimate on dues invoice	21.0%	35.0%	2.0%	-	-
Revised Estimate – June 2011	26.0%	36.0%	2.0%	6.0%	50%

Please do not hesitate to contact me at (202) 508-5540 or jschlenker@eei.org if you have any questions.

Sincerely,

John Schlenker
CFO & Treasurer

701 Pennsylvania Avenue, N.W. | Washington, D.C. 20004-2696 | 202.508.5000 | www.eei.org

Power by Association℠

Edison Electric Institute

March 29, 2012

Dear Committee Members:

We have completed the calculation of EEI's actual final expenditures relating to influencing legislation for calendar year 2011. A total of 21.3% of our regular dues was devoted to non-deductible activities in 2011. In addition, 29.1% of the assessment for the SFA for Industry Issues, 6.0% of the assessment for the SFA for Environment, 8.2% of the assessment for the Utility Solid Waste Activities Group ("USWAG"), and 68.2% of the assessment for the Water Advocacy Coalition (WAC) were devoted to non-deductible activities in 2011. These percentages may affect the extent to which your 2011 EEI dues and SFA payments qualify as a deductible business expense.

These actual figures differ from the earlier estimates contained in your 2011 dues invoice and our letter dated June 9, 2011. For your convenience, a chart with original and revised estimates for 2011 and 2012, as well as actual results for 2011, is provided below. The actual percentages for calendar year 2012 will be provided to you by mid-2013.

Summary of 2011 and 2012 Estimated, Revised and Actual Percentages

	Regular Activities	Separately Funded Activities (SFA)			
	Core Dues	Industry Issues	Environment	USWAG	WAC
2011					
Original Estimate on dues invoice	21.0%	35.0%	2.0%	-	-
Revised Estimate – June 2011	26.0%	36.0%	2.0%	6.0%	50%
Actual/Final	**21.3%**	**29.1%**	**6.0%**	**8.2%**	**68.2%**
2012					
Original Estimate on dues invoice	26.0%	36.0%	2.0%	-	-
Revised Estimate – March 2012	22.0%	34.0%	6.0%	9.0%	75.0%

Please do not hesitate to contact me at (202) 508-5540 or jschlenker@eei.org if you have any questions.

Sincerely,

John Schlenker
CFO & Treasurer

701 Pennsylvania Avenue, N.W. | Washington, D.C. 20004-2696 | 202.508.5000 | www.eei.org

Power by Association℠

Edison Electric Institute

March 27, 2013

Dear Committee Members:

We have completed the calculation of EEI's expenditures relating to influencing legislation for calendar year 2012. A total of 17.9% of our regular dues was devoted to non-deductible activities in 2012. In addition, 75.4% of the assessment for the SFA for Industry Issues, 19.9% of the assessment for the SFA for Environment, 9.6% of the assessment for the Utility Solid Waste Activities Group ("USWAG"), and 95.6% of the assessment for the Water Advocacy Coalition (WAC) were devoted to non-deductible activities in 2012. These percentages may affect the extent to which your 2012 EEI dues and SFA payments qualify as a deductible business expense.

These actual figures differ from the earlier estimates contained in your 2012 dues invoice and our letter dated March 29, 2012. For your convenience, a chart with original and revised estimates for 2012 and 2013, as well as actual results for 2012, is provided below. The actual percentages for calendar year 2013 will be provided to you by mid-2014.

Summary of 2012 and 2013 Estimated, Revised and Actual Percentages

	Regular Activities	Separately Funded Activities (SFA)			
	Core Dues	Industry Issues	Environment	USWAG	WAC
2012					
Original Estimate on dues invoice	26.0%	36.0%	2.0%	-	-
Revised Estimate – March 2012	22.0%	34.0%	6.0%	9.0%	75.0%
Actual/Final	**17.9%**	**75.4%**	**19.9%**	**9.6%**	**95.6%**
2013					
Original Estimate on dues invoice	22.0%	34.0%	10.0%	-	-
Revised Estimate – March 2013	18.0%	40.0%	10.0%	10.0%	95.0%

Please do not hesitate to contact me at (202) 508-5540 or jschlenker@eei.org if you have any questions.

Sincerely,

John Schlenker
CFO & Treasurer

701 Pennsylvania Avenue, N.W. | Washington, D.C. 20004-2696 | 202.508.5000 | www.eei.org

Power by Association℠

Edison Electric Institute

March 26, 2014

Dear EEI Members:

We have completed the calculation of EEI's expenditures relating to influencing legislation for calendar year 2013. A total of 15.2% of our regular dues was devoted to non-deductible activities in 2013. In addition, 37.6% of the assessment for the SFA for Industry Issues, 7.2% of the assessment for the Utility Solid Waste Activities Group ("USWAG"), and 100% of the assessment for the Water Advocacy Coalition (WAC) was devoted to non-deductible activities in 2013. These percentages may affect the extent to which your 2013 EEI dues and SFA payments qualify as a deductible business expense.

The actual figures differ from the earlier estimates contained in your 2013 dues invoice and our letter dated March 27, 2013. For your convenience, a chart with original and revised estimates for 2013 and 2014, as well as actual results for 2013, is provided below. The actual percentages for calendar year 2014 will be provided to you in March, 2015.

Summary of 2013 and 2014 Estimated, Revised and Actual Percentages

	Regular Activities	Separately Funded Activities (SFA)			
	Core Dues	Industry Issues	Environment	USWAG	WAC
2013					
Original Estimate on dues invoice	22.0%	34.0%	10.0%	-	-
Revised Estimate – March 2013	18.0%	40.0%	10.0%	10.0%	95.0%
Actual/Final	**15.2%**	**37.6%**	**0.0 %**	**7.2%**	**100.0%**
2014					
Original Estimate on dues invoice	18.0%	40.0%	10.0%	-	-
Revised Estimate – March 2014	16.0%	30.0%	0.0%	7.0%	100.0%

Please do not hesitate to contact me at (202) 508-5540 or jschlenker@eei.org if you have any questions.

Sincerely,

John Schlenker
CFO & Treasurer

701 Pennsylvania Avenue, N.W. Washington, D.C. 20004-2696 202.508.5000 www.eei.org

Power by Association

Edison Electric Institute

March 12, 2015

Dear EEI Members:

We have completed the calculation of EEI's expenditures relating to influencing legislation for calendar year 2014. A total of 12.7% of our regular dues was devoted to non-deductible activities in 2014. In addition, 27.6% of the assessment for the Industry Issues Separately Funded Activity (SFA), 6.2% of the assessment for the Utility Solid Waste Activities Group ("USWAG"), and 68.8% of the assessment for the Water Advocacy Coalition (WAC) was devoted to non-deductible activities in 2014. These percentages may affect the extent to which your 2014 EEI dues and SFA payments qualify as a deductible business expense.

The actual figures differ from the earlier estimates contained in your 2014 dues invoice and our letter dated March 26, 2014. For your convenience, a chart with original and revised estimates for 2014 and 2015, as well as actual results for 2014, is provided below. The actual percentages for calendar year 2015 will be provided to you in March, 2016.

Summary of 2014 and 2015 Estimated, Revised and Actual Percentages

	Regular Activities	Separately Funded Activities (SFA)			
	Core Dues	Industry Issues	Environment	USWAG	WAC
2014					
Original Estimate on dues invoice	18.0%	40.0%	10.0%	-	-
Revised Estimate – March 2014	16.0%	30.0%	-	7.0%	100.0%
Actual/Final	**12.7%**	**27.6%**	-	**6.2%**	**68.8%**
2015					
Original Estimate on dues invoice	13.0%	25.0%	-	7.0%	100.0%
Revised Estimate – March 2015	16.0%	30.0%	-	7.0%	70.0%

Please contact me at (202) 508-5540 or jschlenker@eei.org if you have any questions.

Sincerely,

John Schlenker
CFO & Treasurer

Edison Electric
INSTITUTE

Power by Association

March 3, 2016

Dear EEI Members:

We have completed the calculation of EEI's expenditures relating to influencing legislation for calendar year 2015. A total of 12.6% of core dues was applied to non-deductible activities in 2015. In addition, 25.8% of the assessment for the Industry Issues Separately Funded Activity (SFA), 4.7% of the assessment for the Utility Solid Waste Activities Group ("USWAG"), and 41.6% of the assessment for the Water Advocacy Coalition (WAC) was applied to non-deductible activities in 2015.

For tax reporting purposes, please use the "original estimate on dues invoice". These percentages may affect the extent to which your 2015 EEI dues and SFA payments qualify as a deductible business expense.

Summary of 2015 and 2016 Lobbying Percentages

	Regular Activities	Separately Funded Activities (SFA)		
	Core Dues	Industry Issues	USWAG	WAC
2015				
Original Estimate on Dues Invoice	13.0%	25.0%	7.0%	100.0%
Revised Estimate – March 2015	16.0%	30.0%	7.0%	70.0%
Actual/Final	12.6%	25.8%	4.7%	41.6%
2016				
Original Estimate on Dues Invoice	12.8%	25.9%	5.7%	42.6%

Please contact me at (202) 508-5540 or jschlenker@eei.org if you have any questions.

Sincerely,
John Schlenker
CFO & Treasurer

WM-7 Allocation of Accounts Receivable and Unbilled Revenue

CUSTOMER FACTORS

OKLAHOMA GAS & ELECTRIC COMPANY
REVASSETS ALLOCATOR DETERMINATION
TEST YEAR ENDING JUNE 30, 2016
DOCKET NO. 16-052-U

LN.	JURISDICTION / CLASS	PROFORMA SALES OF ELECTRICITY	"REVASSETS" ALLOCATOR		Booked SALES OF ELECTRICITY	Revised "REVASSETS" ALLOCATOR
1	**TOTAL (Sum Ln 2 thru 3) (Excludes Other Oper. Revenues)**	**$1,116,013,075**	**99.9999%**	**$**	**2,188,128,313**	
2	**JURISDICTIONS NOT AT ISSUE**	**$1,024,246,275**	**91.7774%**	**$**	**2,009,425,885**	**91.8332%**
3	**ARKANSAS RETAIL JURIS. (Sum Lns 4, 8, 9, 21, & 36) - error left out 17 and 20**	**$91,766,800**	**8.2225%**	**$**	**178,702,428**	**8.1670%**
4	**TOTAL RESIDENTIAL (Sum Ln 5 thru 7)**	**$32,862,607**	**2.9444%**	**$**	**58,362,144**	**2.6673%**
5	RESIDENTIAL - STANDARD S/L 5	$30,494,294	2.7322%	$	53,390,622	**2.4400%**
6	RESIDENTIAL - TOU S/L 5	$469,834	0.0421%	$	961,290	**0.0440%**
7	RESIDENTIAL - VPP S/L 5	$1,898,479	0.1701%	$	4,010,232	**0.1834%**
8	**NOT USED**	**$0**	**0.0000%**			
9	**TOTAL GENERAL SERVICE (Ln 10 + Ln 14)**	**$9,983,989**	**0.8947%**	**$**	**17,813,097**	**0.8141%**
10	**TOTAL GENERAL SERVICE - STANDARD (Sum Ln 11 thru 13)**	**$9,407,985**	**0.8430%**	**$**	**16,682,857**	**0.7624%**
11	GENERAL SERVICE - STANDARD S/L 2	$0	0.0000%	$	-	**0.0000%**
12	GENERAL SERVICE - STANDARD S/L 3	$18,363	0.0016%	$	48,211	**0.0022%**
13	GENERAL SERVICE - STANDARD S/L 5	$9,389,622	0.8414%	$	16,634,646	**0.7602%**
14	**TOTAL COMMERCIAL TOU (Ln 15 + Ln 16 + Ln 17 + Ln 20)**	**$576,004**	**0.0517%**	**$**	**1,130,240**	**0.0517%**
15	GENERAL SERVICE TOU S/L 5	$125,817	0.0113%	$	242,655	**0.0111%**
16	GENERAL SERVICE VPP S/L 5	$331,223	0.0297%	$	676,764	**0.0309%**
17	**TOTAL MUNICIPAL PUMPING (Ln 18 + Ln 19)**	**$61,436**	**0.0055%**	**$**	**118,155**	**0.0054%**
18	MUNI PUMPING S/L 4	$0	0.0000%	$	364	**0.0000%**
19	MUNI PUMPING S/L 5	$61,436	0.0055%	$	117,791	**0.0054%**
20	ATHLETIC FLD LIGHT S/L 5	$57,528	0.0052%	$	92,666	**0.0042%**
21	**TOTAL POWER & LIGHT (Ln 22 + Ln 29)**	**$45,716,472**	**4.0963%**	**$**	**98,281,172**	**4.4916%**
22	**TOTAL POWER & LIGHT - STANDARD (Sum Ln 23 thru 26)**	**$26,778,157**	**2.3994%**	**$**	**50,798,585**	**2.3216%**
23	POWER & LIGHT STANDARD S/L 1	$0	0.0000%	$	-	**0.0000%**
24	POWER & LIGHT STANDARD S/L 2	$1,142,159	0.1023%	$	2,609,869	**0.1193%**
25	POWER & LIGHT STANDARD S/L 3	$7,634,630	0.6841%	$	14,227,818	**0.6502%**
26	POWER & LIGHT STANDARD - DISTRIBUTION (Ln 27 + Ln 28)	$18,001,368	1.6130%	$	33,960,898	**1.5521%**
27	POWER & LIGHT STANDARD S/L 4	$155,781	0.0140%	$	197,224	**0.0090%**
28	POWER & LIGHT STANDARD S/L 5	$17,845,587	1.5990%	$	33,763,674	**1.5430%**
29	**TOTAL POWER & LIGHT - TOU (Sum Ln 30 thru 33)**	**$18,938,315**	**1.6969%**	**$**	**47,482,587**	**2.1700%**
30	POWER & LIGHT TOU S/L 1	$7,321,415	0.6560%	$	20,112,554	**0.9192%**
31	POWER & LIGHT TOU S/L 2	$1,234,162	0.1106%	$	3,084,387	**0.1410%**
32	POWER & LIGHT TOU S/L 3	$7,017,739	0.6288%	$	17,162,891	**0.7844%**
33	POWER & LIGHT TOU - DISTRIBUTION (Ln 34 + Ln 35)	$3,364,999	0.3015%	$	7,122,755	**0.3255%**
34	POWER & LIGHT TOU S/L 4	$0	0.0000%	$	-	**0.0000%**
35	POWER & LIGHT TOU S/L 5	$3,364,999	0.3015%	$	7,122,755	**0.3255%**
36	**TOTAL LIGHTING (Excluding AFL) (Ln 37 + Ln 38)**	**$3,084,768**	**0.2764%**	**$**	**4,035,194**	**0.1844%**
37	MUNICIPAL LIGHTING S/L 5	$1,096,680	0.0983%	$	1,406,917	**0.0643%**
38	OUTDOOR SEC. LIGHTING S/L 5	$1,988,088	0.1781%	$	2,628,277	**0.1201%**

WM-8 Excerpt from Prepared Testimony of William Perea Marcus in Public Utilities Commission of Texas Docket 44941 (December, 2015)

SOAH DOCKET NO. 473-15-5257
PUC DOCKET NO. 44941

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

DIRECT TESTIMONY

OF

WILLIAM PEREA MARCUS

ON BEHALF OF THE

OFFICE OF PUBLIC UTILITY COUNSEL

DECEMBER 11, 2015

SOAH DOCKET NO. 473-15-5257
PUC DOCKET NO. 44941

DIRECT TESTIMONY
OF WILLIAM PEREA MARCUS

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III. PARTIAL REQUIREMENTS CLASS DEFINITION AND RATE DESIGN

A. A Partial Requirements Rate Class Should Not Be Adopted

Q. WHAT IS EPE RECOMMENDING IN THIS CASE?

A. EPE is recommending that the Commission adopt a separate "partial requirements" residential rate class in this case (applying to those residential customers with DG) that would be subject to a higher customer charge, a residential demand charge, and lower energy rates. The Company suggests that these customers should face a base rate increase in excess of 100% to equalize the rate of return. While EPE applies gradualism to develop its proposed rate level, it still increases base rates for these customers by almost 24% after gradualism, while reducing energy charges.

Q. WILL YOU SUMMARIZE YOUR RECOMMENDATION?

A. My primary recommendation is to retain one residential class. Therefore, I recommend that the Commission reject breaking out the residential customers with DG from the residential class and that it make no changes at all.

Q. WHAT IS THE SITUATION WITH CUSTOMER-OWNED DISTRIBUTED GENERATION IN EPE'S SERVICE AREA?

A. The partial requirements rate design is a solution in search of a problem. There were just over 500 residential customers with DG out of 300,000 total customers as of EPE's filing of the rate case and only 747 such customers as of September 2015.[41]

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[41] *See* EPE Response to ECO El Paso's RFI No. 1-17.

Further, these customers are not concentrated on individual circuits, so they do not have large impacts on the distribution system. For those Texas circuits identified in EFCA RFI No. 1-8, almost half of the circuits have no residential customers with DG, and the average circuit with any residential customers with DG has an installed capacity averaging half a percent of the size of the circuit.[42] These circumstances do not warrant separate treatment for customers with distributed generation.

Q. WILL YOU PROVIDE SOME BACKGROUND ON THE COMMISSION'S DEFINITIONS OF CUSTOMER CLASS AND RATE CLASS?

A. The Commission's rules include the following definitions of "customer class" and "rate class":

(23) Customer class — A group of customers with similar electric service characteristics (e.g., residential, commercial, industrial, sales for resale) taking service under one or more rate schedules. Qualified businesses as defined by the Texas Enterprise Zone Act, Texas Government Code, Title 10, Chapter 2303 may be considered to be a separate customer class of electric utilities.

(100) Rate class — A group of customers taking electric service under the same rate schedule.[43]

Q. HOW ARE CUSTOMER CLASSES TYPICALLY DEFINED IN TEXAS?

A. Typically, they involve a "group of customers with similar electric service characteristics," as provided in the Commission's rules. In addition, a single residential

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[42] See my workpapers for the calculation.

[43] 16 TAC § 25.5(23) and (100).

class was called for under the Uniform Cost Allocation System for Transmission and Distribution Utilities.[44] The Commission recently affirmed that the residential class should be unified in discussing the SPS rate case.[45]

Q. DO YOU BELIEVE THAT END USE CHARACTERISTICS SHOULD BE CONSIDERED WHEN DETERMINING WHETHER THERE SHOULD BE A SINGLE RESIDENTIAL CLASS?

A. No. It would be unreasonable to have separate classes, for example, for residential customers with and without space heating, because that is a customer end-use behind the meter. Similarly, the Commission does not develop customized rates for customers who switch from a swamp cooler to an air conditioner (increasing peak demand per unit of energy). There are no customized energy rates for customers who reduce their energy usage by installing efficient lighting and weatherizing their dwelling (even if they might potentially decrease energy use by more than the reduction in demand or customer costs). In fact, Texas offers energy efficiency programs to encourage such customers to cut electricity use. By the same token, just because about 0.2% of residential customers use a photovoltaic device does not mean that such a device should be the marker for a customer class.

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[44] Docket No. 22344, Order No. 40, pp. 4-5.

[45] PUC Open Meeting Discusssion on Docket No. 43695 (Dec. 3, 2015).

Q. ARE THERE OTHER CONSIDERATIONS POINTING TOWARD A SINGLE RESIDENTIAL CLASS?

A. Yes, PURA also envisions a single residential class. OPUC's enabling legislation, PURA § 13.003(a)(3)(A) states in pertinent part, that OPUC "may appear or intervene . . . as a matter of right on behalf of: residential consumers, as **a class**, in any proceeding before the commission." (Emphasis added).

Q. SHOULD RESIDENTIAL CUSTOMERS WITH DISTRIBUTED GENERATION BE IN THEIR OWN RATE CLASS?

A. No, given the long-standing definition of rate classes in Texas, it is inappropriate to separate residential customers with distributed generation into a new rate class. It should also be noted that Texas has no legislation requiring the examination of distributed generation customers separately from other customers and that these customers are not numerous and therefore have little impact on system planning and operation.

In addition, the New Mexico Public Regulation Commission recently rejected EPE's proposal to establish a partial requirements class for the Company's New Mexico residential customers.[46] As a result, if a partial requirements class were adopted for EPE's Texas residential customers with distributed generation, they would be treated differently than similarly situated customers of the Company in New Mexico.

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[46] NMPRC Case No. 15-00127-UT, *In the Matter of the Application of El Paso Electric Company for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 236*, Order Granting Interlocutory Appeals (Oct. 28, 2015).

Q. HOW DOES EPE'S DECISION TO MOVE RESIDENTIAL CUSTOMERS WITH DG INTO A SEPARATE RATE CLASS ARTIFICIALLY INFLATE THEIR REVENUE REQUIREMENTS?

A. Each rate class has its own class maximum diversified demand (MDD) used to allocate primary distribution costs (and secondary distribution costs in my cost of service analysis above). EPE has carved these 500 customers out of over 275,000 residential customers to assign them a class MDD on a different day and time than their immediate neighbors in the residential class. These customers are on the same circuits and are very small portions of the loads on those circuits. By giving the partial requirements "class" a higher MDD, EPE assigns them a larger amount of costs than for other residential customers. The assignment of these extra costs is unjustified because these customers are not causing the peaks that drive distribution demand. This treatment artificially inflates costs.

Q. WILL YOU COMMENT FURTHER ON DISTRIBUTION COSTS AS THEY WOULD RELATE TO A SEPARATE PARTIAL REQUIREMENTS CLASS?

A. The reductions in distribution system loads from small distributed generation customers, both due to use by the DG customers and the export of energy into the distribution system, are absorbed in a localized area and do not affect most of the distribution system, other than to reduce line loadings and marginal line losses. The marginal line losses avoided by residential DG are likely to be higher than embedded line losses used in the cost of service study, and thus, provide an extra unquantified benefit of DG. If a DG customer feeds power to its close neighbors for a few hours, the rest of the distribution system is largely unaffected. In many cases, excess generation may not even reach above the line transformer into the feeder line. As a result, DG customers should not be assigned artificially high distribution costs resulting from placing them in a separate rate class from their other residential neighbors, when their presence on the system is, if anything, beneficial.

Q. ARE THERE OTHER ISSUES ASSOCIATED WITH THE COST OF SERVICE STUDY FOR RESIDENTIAL CUSTOMERS WITH DG?

A. Yes. EPE completely ignores the value of power exports in the cost of service study. The entire study is based on deliveries to the customer, except that energy is the net of energy delivered to the customer and exported by the customer. As a result, the cost of service study gives no explicit credit for the value of power that residential customers with DG delivered to EPE.

For residential customers with DG, EPE has stated that it calculates a credit against the value of exported power that is less than the rate paid to customers under net energy metering (NEM). This credit is based on solar energy costs at a large-scale station near a utility powerplant and does not include any avoidance of transmission or distribution capacity or losses.[47] However, even this low credit is not included as an offset to the costs in the cost of service study, thereby producing a biased outcome.

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[47] Direct Testimony of James Schichtl, pp. 35-36.

B. Demand Charges Should Be Rejected for All Residential Customers, Including DG Customers

Q. HOW IS EPE PROPOSING TO DESIGN RATES FOR RESIDENTIAL CUSTOMERS WITH DISTRIBUTED GENERATION?

A. EPE is proposing to move residential customers with DG into a new "partial requirements" class that has a higher customer charge than the residential class ($15 instead of $10). EPE is also proposing to apply a separate demand charge to these customers for the first time to recover distribution costs.

Q. WHAT IS A DEMAND CHARGE?

A. A demand charge is a charge based on the maximum use of the customer in a very narrow period within a month, generally 15 minutes to a half-hour.

Q. WILL YOU COMMENT ON THE CUSTOMER COSTS FOR DG CUSTOMERS?

A. The only reason that the customer cost is higher for so-called partial requirements customers is that they have extra meters and more expensive meters, raising the costs of metering and meter reading. Costs of service drops, customer accounting, and similar costs are the same. The EPE residential class as a whole does not have smart meters, unlike most of the rest of Texas. Therefore, there are a variety of smart meters, bi-directional meters, extra meters measuring solar loads only, and similar sorts of meters for this group of customers.[48] There are 780 meters for 422 customers in the Test Year. It is not clear that all these meters are in fact necessary—particularly since load research

[48] See Schedule P-11.

meters have only been installed on 38 DG customers for an entire year—barely enough for a statistically significant sample. The customer costs would have been identical without all the extra meters—many of which may not be necessary now, and none of which would be necessary had EPE installed smart meters for all its residential customers like most other Texas utilities. Therefore, I see no reason to raise the customer charge for DG customers to pay for meters that may be at least in part superfluous. While a case might be made that shareholders should pay for some of the excess meters, I do not propose such an outcome. Instead, I include the costs of the extra meters into the residential class as a whole (including residential customers with and without DG) for purposes of cost allocation.

Q. WILL YOU PROVIDE SOME OVERVIEW COMMENTS ON THE DEMAND CHARGE?

A. As discussed in the cost allocation section above, I disagree with EPE on the allocation of secondary distribution demand costs—for purposes of both cost allocation and rate design. As a result, I do not believe that any costs should be allocated to any residential customers—whether they have DG or not—by the sum of customer NCP demand. Having made that point, one must look at whether demand charges based on other measures of demand (Maximum Diversified Demand (MDD) or 4 Coincident Peak Months (4CP)) are reasonable.

Q. WHAT ANALYSIS IS APPROPRIATE TO DETERMINE WHETHER DEMAND CHARGES ARE REASONABLE AND COST-BASED FOR SPECIFIC SETS OF CUSTOMERS?

A. The analysis involves a review of the coincidence of the customer's own maximum demand with the demands used to allocate costs to customer classes (4CP or MDD), as well as a review of whether the customer's NCP, when combined with energy in the relevant time period, explains the customer's MDD or 4CP demand.

Q. HOW IS THE COINCIDENCE OF THE CUSTOMER'S NCP WITH OTHER MEASURES OF DEMAND DETERMINED?

A. Coincidence is related to the concept of load diversity that I discussed with respect to secondary distribution transformer loads earlier in my testimony. The coincidence of the sum of the customers' NCP demand is calculated by taking the other measure of demand being analyzed (for example 4CP for generation and transmission and MDD for distribution) divided by the sum of the customer NCP demand. The sum of the customer NCP demands will always be larger than the more diversified demands at 4CP or MDD. So the coincidence factor is always less than one. The lower the coincidence factor, the worse the sum of customer NCPs (and thus a demand charge) will be in actually matching up with the demand-related costs that the utility is proposing to collect through NCP demand.

Q. WHAT MUST BE CONSIDERED TO DETERMINE WHETHER A DEMAND CHARGE IS REASONABLY COST-BASED?

A. The questions when analyzing the cost basis of demand charges are (1) whether the customer NCP has a systematic bias (i.e., smaller or lower load factor customers have a lower coincidence than larger or higher load factor customers), (2) whether there are large amounts of variation in the coincidence among customers of the same size (so that the coincidence is so variable that it cannot be used to establish a demand charge without harming large numbers of customers by charging them rates that are not cost-based), and (3) whether the 4CP and MDD demand costs can be better predicted by energy use in a relevant time period than by maximum customer NCP demand in the same time period. To the extent that energy use is a better predictor of MDD or 4CP than maximum NCP demand, a demand charge is a less accurate and more crude method of setting rates than an energy charge. The third question is answered by use of regression equations, which I discuss further below.

Q. DO YOU BELIEVE THAT RESIDENTIAL DEMAND CHARGES MAKE SENSE?

A. No. They are not cost-based because there is a large variation in the coincidence of NCP demand for residential customers, which can be driven by random fluctuations, particularly when measured on a short interval, with coincident peak demand and the class coincident peak. In addition, small customers have a higher NCP demand (caused by randomly turning on equipment) as compared to their coincident peak demands or class MDD. This means that using a demand charge to collect CP or MDD will systematically overcharge the average of small residential customers.

Q. DID YOU CONDUCT ANY ANALYSIS TO DEMONSTRATE THIS POINT FOR EPE'S RESIDENTIAL CLASS?

A. Yes. I analyzed EPE's load study by breaking it into groupings by average monthly usage and by comparing average usage to various measures of demand (the average 4CP for production and transmission costs, the class MDD, and the customer's own NCP).[49] I examined coincidence (the relationship between NCP and other measures of demand like MDD and 4CP) and the differences in load factor[50] by size of customers.[51] The three figures below present data from EPE's load study for the residential class as a whole. Exhibit WM-6 contains the data used to construct them.

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[49] I excluded residential customers with DG from the residential sample, not because I believe that they should be analyzed separately, but because EPE's statistical sampling techniques separated them out and assigned different statistical weights to residential customers with and without DG. Adding them back into the sample is not feasible without very complex statistical analysis.

[50] The load factor is the average load divided by the peak load being measured.

[51] From EPE's response to EFCA RFI No. 3-73 (requesting data in OPUC RFI No. 6-04 in spreadsheet format). To conduct the analysis I excluded 12 customers in the sample missing at least 20 summer or winter days as unrepresentative.

Figure 2: Energy and Demand by Size of Residential Customer

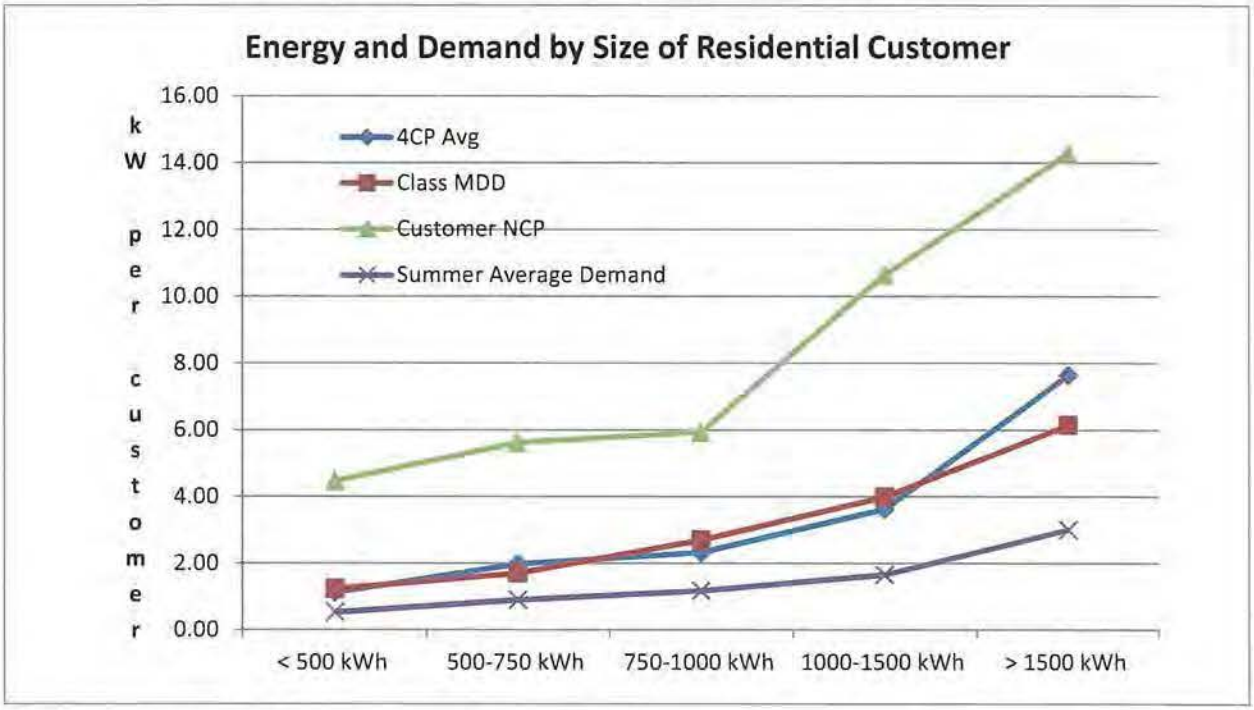

Figure 2 shows the loads for residential customers of different size groups. EPE's strata were used to weight the specific customers in each group. It shows that from the smallest to the largest customers, energy use rises by 5.7 times, 4CP system peak rises 6.8 times, the MDD rises 5.0 times, but the NCP rises only 3.0 times. This result occurs because customers turn on significant amounts of equipment simultaneously and at random for short periods of time, regardless of size.

Figure 3: Load Factors by Size of Residential Customer

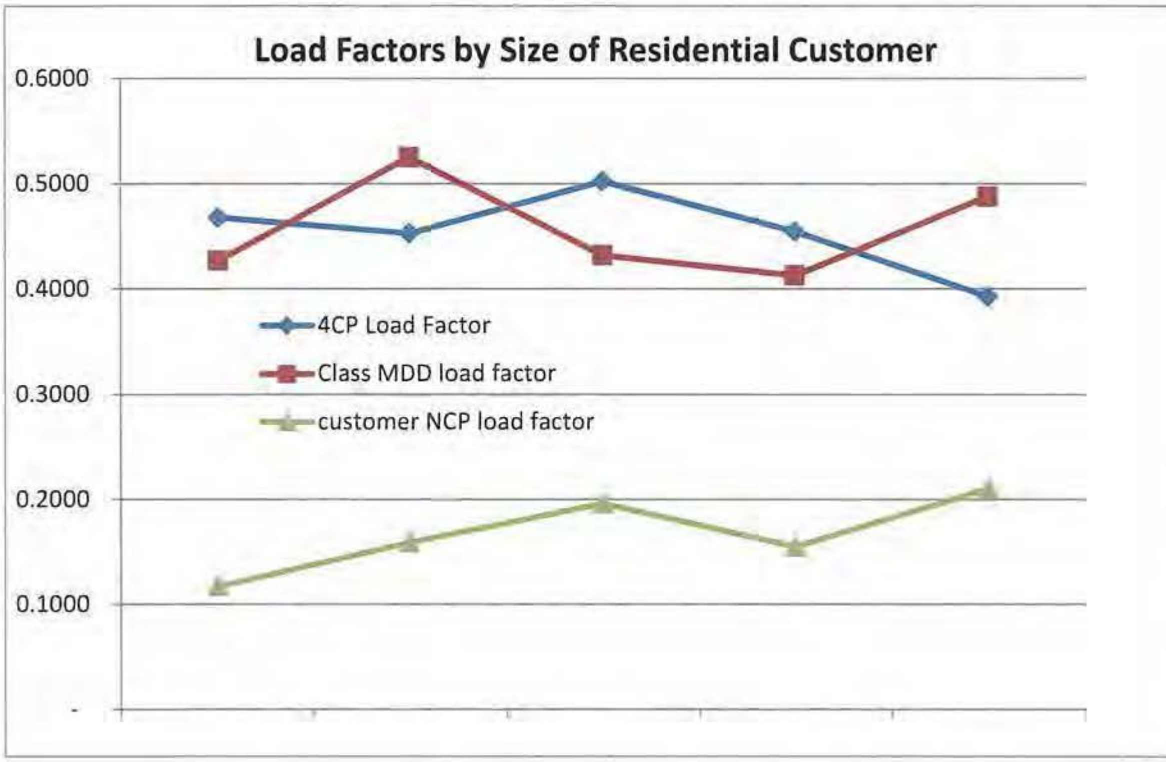

Figure 3 shows that the system load factors (4CP and MDD) are relatively constant across size ranges of customers, with some decline in the 4CP load factor for larger customers, many of whom are likely to live in larger dwellings and have central air conditioning. If the system load factors (based on 4CP and MDD) of smaller customers are the same as for larger customers, then the demand-related cost of service for those customers is approximately equal. In the case of the 4CP load factors, smaller customers may have slightly better load factors, than larger customers which would mean that their costs of generation and transmission capacity may actually be slightly lower. In any event, it is the system load factors that are important in determining the costs of serving customers.

However, the NCP load factor goes up because customers who use more energy use it more intensively in their dwellings rather than randomly turning on appliances for short periods. But the NCP load factor—although the basis for a demand charge—is irrelevant to how the system as a whole is planned and operated. Therefore, assigning higher costs to customers with lower NCP load factors—which is what a demand charge does—is not cost-based if the underlying system load factors are similar.

Figure 4: Coincidence by Size of Residential Customer

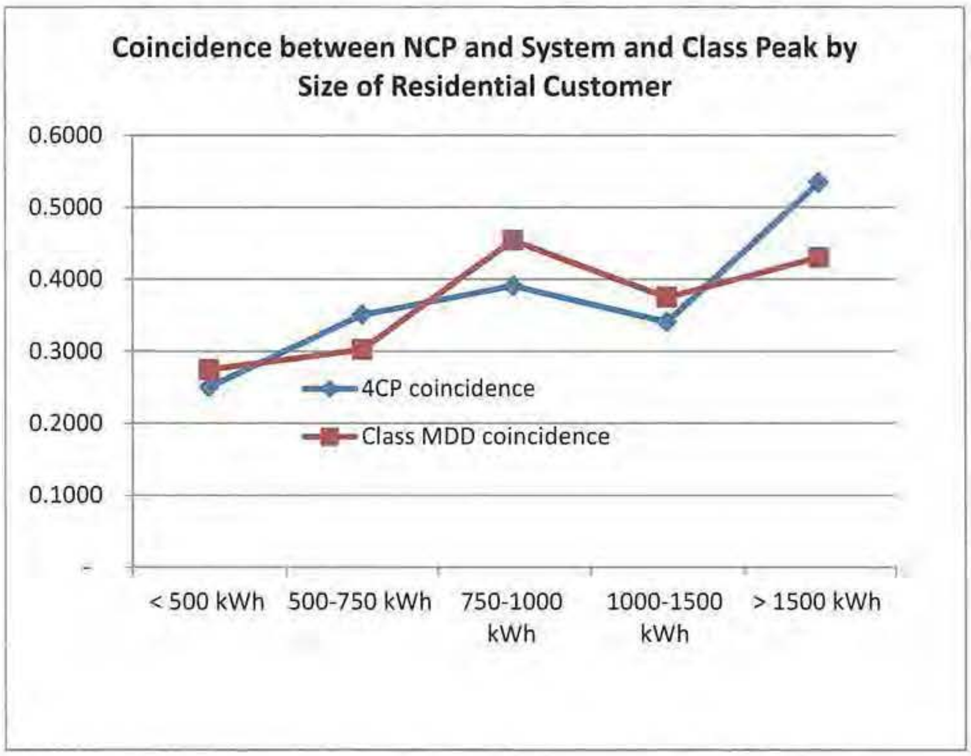

Figure 4 illustrates this point and identifies the coincidence between NCP and system peaks. It indicates that demand charges are highly problematic. The coincidence factors are not figures like 80% (as observed for general service customers with load factors above 40% in the SPS case) but are no higher than 50%. Thus, there is considerably more variation in customer NCP demand for residential customers than for non-residential customers. Moreover, coincidence is much lower for small residential customers than for large ones. Thus using a maximum demand charge to collect demand costs will systematically overcharge small customers and undercharge larger customers on the EPE system.

Q. WHAT OTHER ANALYSIS DID YOU CONDUCT FOR THE RESIDENTIAL CLASS?

A. I also conducted a regression analysis relating average 4CP and Class MDD to customers' energy use and to maximum NCP summer demand. Exhibit WM-7 contains the results.

A regression equation is a statistical method of fitting a dependent variable (in this case 4CP or MDD) to one or more other independent variables to determine the best fit and the coefficients associated with each variable that give the least amount of variation (measured by the least squared error). A regression equation is more detailed than a simple coincidence analysis, as it takes into account all of the individual data points representing individual observations. In this specific case, the dependent variable was the measure of system peak (4CP or MDD). The two independent variables used (separately or in combination) were the customer NCP in the six summer months and kWh usage in the six-month summer period.

Q. WHAT WERE YOUR FINDINGS?

A. I found for residential customers that NCP demand is a worse variable for explaining CP demand than energy use. Energy use by itself explained 82% of the variation in average

4CP loads, while NCP demand by itself explained only 66%. In other words, if an analyst were to choose only one variable to explain 4CP loads (or MDD loads), NCP demand is a worse variable to pick than summer energy use. Using both variables, 84% of the variation was explained, but most of the variation was explained by differences in energy use. While the NCP variable was statistically significant it only had a coefficient of 0.14 (i.e., after considering energy, only 14% of NCP was related to 4CP).

For Class MDD, the relationships were less strong but similar. NCP demand was still a weaker variable. Energy use by itself explained 55% of the variation in Class MDD, while NCP demand explained only 47%. Again, NCP would be a worse choice for a single variable. Using both variables, 57% of the variation was explained, and NCP was statistically significant but again only had a coefficient of 0.14, showing the same weak explanatory power as the 4CP equation.

Q. WHAT IS YOUR CONCLUSION FROM THE COINCIDENCE ANALYSIS AND REGRESSION ANALYSIS OF RESIDENTIAL DEMAND CHARGES?

A. This information suggests that demand charges for generation and transmission and distribution should not be used for residential customers. The NCP variable has only a weak explanatory power when examining both 4CP and MDD. The biases and problems with difference in coincidence by size of customer discussed overcome any weak explanatory power that such a variable might have.

Q. DID YOU CONDUCT SIMILAR ANALYSES WITH EPE'S LOAD SAMPLE OF RESIDENTIAL CUSTOMERS WITH DG?

A. Yes. However, with only 38 data points, my ability to develop the same level of information as for the residential class as a whole is more statistically limited. Because of these statistical limitations of EPE's sample, I did not produce figures equivalent to Figures 2-4 above. In addition, though I do not agree with using a different Class MDD load for residential customers with DG than for the entire residential class, those were the data provided to me by EPE, and I analyzed them. The load analysis is shown in Exhibit WM-8.

Nevertheless, as with the residential class, coincidence with CP and class NCP are quite variable for the residential customers with DG. Coincidence factors with 4CP were actually lower than for other residential customers, suggesting a weak relationship between NCP and the system peak. With a class peak at 7:00 pm identified by EPE, coincidence factors were higher for the residential customers with DG (though still not in the 80% range experienced for non-residential customers with load factors above 40%) but with the common class peak that I recommend for a single residential class, this outcome would likely be erased. Moreover, there is significant variation in the coincidence with NCP and MDD among the customers in the sample. The coincidence was 49.7%, but the standard deviation of coincidence was 24%, meaning that many individual customers had coincidence below 30% like other residential customers, and the large variability in coincidence brings the reasonableness of a demand charge into question.

Q. DID YOU PRODUCE A REGRESSION ANALYSIS FOR CUSTOMERS WITH DG SIMILAR TO THAT FOR THE RESIDENTIAL CLASS AS A WHOLE?

A. Yes. These equations (given in Exhibit WM-9) show that the Customer NCP predicts absolutely nothing for DG customers. When a regression is prepared relating 4CP or MDD to only the Customer NCP, the results of the equation are statistically insignificant. In other words, there is no relationship at all. This means that the customer's maximum demand cannot be used to explain or project either the customer's CP demand or its NCP demand. Regressions including only an energy variable show significance, as expected, although they explain less of the variation in the data for residential customers with DG than for other residential customers.

When both the NCP variable and the energy variable are brought into the equations, the results are worse still. The NCP coefficient is negative (statistically significant in one case, insignificant in the other). The equations show that the lower the customer's NCP demand, after adjusting for energy use, the higher the customer's 4CP or MDD demand. Such a result does not make physical sense.

Q. WHAT DO YOU CONCLUDE REGARDING DEMAND CHARGES FOR EPE'S RESIDENTIAL CUSTOMERS WITH DG?

A. The coincidence analysis shows great variation among EPE's residential customers with DG (although the very small size of the sample does not allow definitive conclusions for subgroups of different-sized residential customers with DG). The regression equations do not show any relationship at all between NCP demands and system 4CP and MDD demands. Therefore, demand charges for these customers are not reasonable.

Q. WHAT DO YOU CONCLUDE ABOUT WHETHER DEMAND CHARGES ARE COST BASED?

A. Demand charges are not cost based both for residential customers as a whole and for those residential customers with DG. Therefore, the Commission should reject them for any residential customers.

Q. DO YOU HAVE ANY FURTHER COMMENTS ON IMPLEMENTATION OF DEMAND CHARGES?

A. While I do not support demand charges—for DG customers or any other residential customers—I must point out that demand charges are both generally unknown to residential customers in areas that do not have them and are complicated to explain. EPE could end up with serious customer acceptance problems if they design a demand charge in a way that customers see as punitive and then do not provide adequate information to customers.

Q. WHY DO YOU SUGGEST THAT RESIDENTIAL CUSTOMERS ARE UNFAMILIAR WITH AND DISTRUST DEMAND CHARGES?

A. A recent focus group study in Ontario, Canada, where time of use (TOU) rates have been in place for several years and customers are thus fairly sophisticated suggests that residential customers do not understand demand charges and believe that such charges are demanding perfection in their conservation efforts. The Ontario Energy Board conducted an analysis with residential focus groups that raised concerns about maximum monthly usage charges (another term for demand charges) in addition to TOU rates that Ontario customers understand:

> The concept of maximum use during peak times is difficult for people to understand and raised concern among a few. There is no template for measuring maximum use that people are used to in the way they understand TOU. It was not obvious how this would be calculated.
>
> Without precise details of this there was concern expressed by some that small lapses in their conservation efforts will mean they will have to pay a high price for that (even if they conserve diligently on the vast majority of days during peak times). So there will be questions of fairness if they have conserved on the vast majority of days during peak demand times and essentially helped to reduce peak consumption.[52]

Q. ARE THERE ADDITIONAL ISSUES WITH EPE'S PROPOSED DEMAND CHARGE FOR RESIDENTIAL CUSTOMERS?

A. Yes. Although I do not support a demand charge for residential customers and do not believe it is reasonable to be adopted, EPE's proposal is particularly troublesome. EPE proposes to implement the demand charge on a 30-minute interval rather than on an hour interval. Individual residential customers have relatively random patterns of energy use, and thus have far less coincidence with peak than large industrial customers. With a 30-minute demand charge, random events having little or nothing to do with cost causation (for example, turning on a hair dryer, coffeepot, microwave, and toaster at the same time to get ready for work on a winter morning) could trigger a significant demand charge. Many of those random spikes are at least partly damped out over an hour.

Additionally, EPE has not proposed sufficient customer education. Imposing a demand charge on a residential customer would be a sea change in the pricing of electric

[52] The Gandalf Group, Ontario Energy Board Distribution Charge Focus Groups: Final Report, October 9, 2013, p. 9.

service for residential customers and would require a monumental customer education effort. There should be a period of time before it is put into effect, and affected customers should be provided education on what a demand charge is, how it works, and how to reduce it. Residential customers would need to understand how the demand charge affects their everyday lives and how particular patterns of electricity consumption affect their bills.

In other words, affected customers should understand that turning on multiple devices at the same time, such as a toaster, hair dryer, and microwave will increase demand charges. Further, customers should understand that gas stoves[53] and gas dryers are prefereable to electric stoves and dryers that could cause demand charges to spike upward. Especially important in EPE's service area, customers should understand that they will be hit hard with demand charges if they convert from swamp coolers to central air conditioning and that they should replace existing air conditioners with more efficient air conditioners. All of these actions would use less instantaneous power and reduce demand charges. Additionally, customers that have invested in weatherizing their dwellings will not save as much under a rate with a demand charge (because weatherization avoids summer peak energy and system peak demand but does not avoid demand charges for individual customers because the air conditioner would still turn on for a shorter duty cycle). All of the measures identified above (some of which are unprofitable for electric utilities and profitable for gas utilities, some of which may not

[53] The 22% of EPE customers with electric stoves and 27% with electric ovens could be especially hit hard with demand charges. *See* Attachment to Response to OPUC RFI 5-22 page 10 of 16. If EPE does not tell them to switch to gas, it will be doing them a disservice.

necessarily be good for society as a whole, and some of which would burden customers with micromanaging their energy use) are ways to reduce residential demand charges. If these charges are going to be implemented, customers must be forewarned and given a toolkit of actions to take to reduce the cost.

C. Design of Rates for Distributed Generation

Q. DO YOU BELIEVE THAT CHANGES TO PARTIAL REQUIREMENTS SCHEDULES ARE NEEDED IN THIS CASE?

A. No. Given that there are only 421 customers in the test year that would qualify for the proposed partial requirements rate schedule (and about 522 customers at the time of filing this case),[54] I do not believe that changes are needed. If the utility has a significant number of residential customers with distributed generation in the future, some moderate changes may be appropriate.

IV. COMMUNITY SOLAR RATES AND UTILITY SCALE SOLAR ALTERNATIVES

Q. WHAT IS EPE PROPOSING FOR A COMMUNITY SOLAR PROGRAM?

A. EPE is proposing to allow residential customers to buy solar energy at their own option from a local project at \$19.07 per kW-month and receive a credit for generation costs based on the plant's production every month multiplied by fixed costs as changed in rate cases, and fuel costs as they change periodically.

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[54] Direct Testimony of James L. Schichtl, p. 30.

Q. WILL YOU BRIEFLY DISCUSS THE COMMUNITY SOLAR PROGRAM AS AN ALTERNATIVE TO CUSTOMERS INSTALLING THEIR OWN SOLAR PROJECTS?

A. I am not opposed to the community solar program, but one must realize that it is in competition with customer-owned solar, and that EPE's shareholders receive unique advantages from community solar owned by the utility that they do not receive from any other investments (except other utility-owned solar projects).

Q. WHAT ARE THOSE ADVANTAGES?

A. In particular, there is the normalization of the Investment Tax Credit for solar energy. Under the Economic Recovery Tax Act of 1981, the normalization rules require that any investment tax credit (ITC), including energy credits, must be amortized over the life of the project. But unlike the treatment of accelerated depreciation, where the Accumulated Deferred Income Taxes are an offset to rate base, and thus a loan from customers at the utility's rate of return, there are preferential features for shareholders from the amortization of the ITC.

There are three options, each of which benefits utilities' shareholders:

1. The ITC principal is amortized for the benefit of ratepayers, but the unamortized balance is not included in rate base. In that case, the utilities receive an interest-free loan from ratepayers that they can invest in other plant that is still included in rate base. The utility thus earns more than its authorized rate of return because of the ITC because it can invest the ITC proceeds in more rate base.

2. The ITC unamortized balance is removed from rate base, but the ITC principal is not amortized for the benefit of ratepayers but goes into a shareholder account. The utility thus earns more than its authorized rate of return because of the ITC because it amortizes the principal over 30 years for the benefit of shareholders.

3. A hybrid of the two methods is allowed.

Q. ARE THERE OTHER PROBLEMS WITH THE ITC FOR RATEPAYERS?

A. Yes. Half of the ITC cannot be depreciated. Therefore ratepayers pay more income taxes on the undepreciable ITC, even though they do not reap the entire rewards of the ITC.

Q. WHAT DOES THIS MEAN?

A. Utility-owned solar has significant advantages for utility companies and significant disadvantages for ratepayers, whether at a community solar program or in other projects. Where there are no such federal normalization requirements, such as under PPAs, it is more likely under competitive bidding and negotiated contracts that the ITC will be passed through to ratepayers in lower cost electricity.

In sum, the incentives in favor of shareholders when utilities own solar projects provide a reason why the utility would tend to prefer those projects relative to customer-owned solar projects.

Q. DOES THIS COMPLETE YOUR TESTIMONY, MR. MARCUS?

A. Yes. Thank you.

Exhibits

William Perea Marcus

Principal Economist
JBS Energy, Inc.

William Perea Marcus has 38 years of experience in analyzing electric and gas utilities.

Mr. Marcus graduated from Harvard College with an A.B. magna cum laude in economics in 1974 and was elected to Phi Beta Kappa. In 1975, he received an M.A. in economics from the University of Toronto.

In July, 1984, Mr. Marcus became Principal Economist for JBS Energy, Inc. In this position, he is the company's lead economist for utility issues.

Mr. Marcus is the co-author of a book on electric restructuring prepared for the National Association of Regulatory Utility Commissioners. He wrote a major report on Performance Based Ratemaking for the Energy Foundation.

Mr. Marcus has prepared testimony and formal comments submitted to the Federal Energy Regulatory Commission, the National Energy Board of Canada, the Bonneville Power Administration, the U.S. Bureau of Indian Affairs, U.S. District Court in San Diego, Nevada County Municipal Court; committees of the Nevada, Ontario and California legislatures and the Los Angeles City Council; the California Energy Commission (CEC), the Sacramento Municipal Utility District (SMUD), the Transmission Agency of Northern California, the State of Nevada's Colorado River Commission, a hearing panel of the Alberta Beverage Container Management Board; two arbitration cases, environmental boards in Ontario, Manitoba, and Nova Scotia; and regulatory commissions in Alberta, Arizona, Arkansas, British Columbia, California, Colorado, Connecticut, District of Columbia, Hawaii, Iowa, Manitoba, Maryland, Massachusetts, Nebraska, Nevada, New Jersey, New Mexico, North Carolina, Northwest Territories, Nova Scotia, Ohio, Oklahoma, Ontario, Oregon, South Carolina, Texas, Utah, Vermont, Virginia, Washington, Wisconsin, and Yukon. He testified on issues including utility restructuring, stranded costs, Performance-Based Ratemaking, resource planning, load forecasts, need for powerplants and transmission lines, environmental effects of electricity production, evaluation of conservation potential and programs, utility affiliate transactions, mergers, utility revenue requirements, avoided cost, and electric and gas cost of service and rate design.

From 1975-1978, Mr. Marcus was a case writer for the Kennedy School of Government, Harvard University, where he wrote case studies on energy, environmental, and urban policy and taught benefit-cost analysis.

From July, 1978 through April, 1982, Mr. Marcus was an economist at the CEC, first in the energy development division and later as a senior economist in the CEC's Executive Office. He prepared testimony on purchased power pricing and economic studies of transmission projects, renewable resources, and conservation programs, and managed interventions in utility rate cases.

From April, 1982, through June, 1984, he was principal economist at California Hydro Systems, Inc., an alternative energy consulting and development company. He prepared financial analyses of projects, negotiated utility contracts, and provided consulting services on utility economics.

Residential Class Load Data Used to Prepare Figures 2-4

Average Monthly Demand	100-500 kWh per month	500-750 kWh per month	750-1000 kWh per month	Over 1000 kWh per month	Total	1000-1500 kWh per month	Over 1500 kWh per month
4CP Avg	1.12	1.97	2.32	4.96	2.18	3.62	7.63
Class MDD	1.22	1.70	2.69	4.71	2.15	3.99	6.14
Customer NCP Summer	4.46	5.61	5.93	11.85	6.20	10.64	14.27
Average Demand	0.52	0.89	1.16	2.10	0.99	1.65	3.00
4CP coincidence	25.0%	35.1%	39.1%	41.9%	35.1%	34.0%	53.5%
Class MDD coincidence	27.5%	30.2%	45.4%	39.7%	34.6%	37.5%	43.0%
4CP load Factor	46.8%	45.3%	50.2%	42.3%	45.3%	45.4%	39.3%
Class MDD load factor	42.7%	52.5%	43.2%	44.5%	46.0%	41.3%	48.8%
customer NCP load factor	11.7%	15.9%	19.6%	17.7%	15.9%	15.5%	21.0%

SUMMARY OUTPUT

Dependent Variable 4CP average with both NCP and Energy

Regression Statistics	
Multiple R	0.918
R Square	0.843
Adjusted R Square	0.840
Standard Error	1.0698
Observations	101

ANOVA

	df	*SS*	*MS*	*F*	*gnificance F*
Regression	2	603.8074	301.9037	263.7732	3.58E-40
Residual	98	112.16669	1.144558		
Total	100	715.97409			

	Coefficients	*andard Errc*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	(0.64942)	0.20270	(3.204)	0.00183	-1.05167	-0.24716
Customer NCP	0.14245	0.04020	3.543	0.000607	0.06267	0.222221
summer kWh	0.000382	0.000036	10.530	8.59E-18	0.00031	0.000454

SUMMARY OUTPUT

4CP vs. Energy

Regression Statistics	
Multiple R	0.907
R Square	0.823
Adjusted R Square	0.821
Standard Error	1.1306
Observations	101

ANOVA

	df	*SS*	*MS*	*F*	*gnificance F*
Regression	1	589.43662	589.4366	461.1616	4.86E-39
Residual	99	126.53747	1.278156		
Total	100	715.97409			

	Coefficients	*andard Errc*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	(0.28852)	0.18520	(1.56)	0.122457	-0.65599	0.078961
summer kWh	0.000485	0.00002	21.47	4.86E-39	0.000441	0.00053

SUMMARY OUTPUT

4CP vs. NCP

Regression Statistics	
Multiple R	0.816
R Square	0.666
Adjusted R Square	0.663
Standard Error	1.554
Observations	101

ANOVA

	df	*SS*	*MS*	*F*	*gnificance F*
Regression	1	476.89566	476.8957	197.4778	2.57E-25
Residual	99	239.07843	2.414934		
Total	100	715.97409			

	Coefficients	*andard Errc*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	(0.65026)	0.2944353	(2.21)	0.029516	-1.23449	-0.06604
Customer NCP	0.48420	0.0344563	14.05	2.57E-25	0.415835	0.552573

SUMMARY OUTPUT

Dependent Variable Class MDD
with both energy and NCP

Regression Statistics	
Multiple R	0.763
R Square	0.583
Adjusted R Squ:	0.574
Standard Error	1.7481
Observations	101

ANOVA

	df	*SS*	*MS*	*F*	*gnificance F*
Regression	2	417.89329	208.9466	68.37204	2.58E-19
Residual	98	299.49043	3.056025		
Total	100	717.38372			

	Coefficients	*'andard Errc*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	(0.21557)	0.33122	(0.651)	0.516674	-0.87286	0.441724
Customer NCP	0.14774	0.06569	2.249	0.026741	0.017386	0.278098
summer kWh	0.000294	0.000059	4.956	3.02E-06	0.000176	0.000411

SUMMARY OUTPUT

Class MDD vs. Energy

Regression Statistics	
Multiple R	0.749
R Square	0.561
Adjusted R Squ:	0.557
Standard Error	1.7836
Observations	101

ANOVA

	df	*SS*	*MS*	*F*	*gnificance F*
Regression	1	402.43388	402.4339	126.4994	2.13E-19
Residual	99	314.94984	3.181311		
Total	100	717.38372			

	Coefficients	*'andard Errc*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.15875	0.29218	0.543	0.588121	-0.421	0.738503
summer kWh	0.000401	0.000036	11.247	2.13E-19	0.00033	0.000472

SUMMARY OUTPUT

Class MDD vs. NCP

Regression Statistics	
Multiple R	0.691
R Square	0.478
Adjusted R Squ:	0.473
Standard Error	1.9450
Observations	101

ANOVA

	df	*SS*	*MS*	*F*	*gnificance F*
Regression	1	342.84539	342.8454	90.62275	1.22E-15
Residual	99	374.53833	3.783215		
Total	100	717.38372			

	Coefficients	*'andard Errc*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	(0.21622)	0.36853	(0.587)	0.558731	-0.94745	0.515015
Customer NCP	0.41055	0.04313	9.520	1.22E-15	0.324977	0.496123

Residential Partial Requirements Load Data

Average Monthly Demand	100-500 kWh per month	500-750 kWh per month	750-1000 kWh per month	Over 1000 kWh per month	Total
4CP Avg	1.36	2.07	1.72	3.39	2.15
Class MDD	3.40	3.39	4.18	6.19	4.23
Customer NCP Summer	5.54	6.57	12.93	9.94	8.51
Average Demand	0.54	0.81	1.18	1.83	1.07
4CP	24.5%	31.5%	13.3%	34.1%	25.2%
Class MDD	61.4%	51.6%	32.3%	62.2%	49.7%
4CP	39.7%	39.1%	68.4%	54.1%	49.9%
Class MDD	15.9%	23.8%	28.2%	29.6%	25.3%
customer NCP	9.7%	12.3%	9.1%	18.4%	12.6%

SUMMARY OUTPUT

Dependent Variable 4CP average
with both NCP and kWh

Regression Statistics	
Multiple R	0.734
R Square	0.538
Adjusted R Square	0.510
Standard Error	1.1623
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*gnificance F*
Regression	2	51.92917	25.96459	19.21899	2.92E-06
Residual	33	44.58255	1.350986		
Total	35	96.51172			

	Coefficients	*andard Err*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.5409827	0.458238	1.180572	0.246213	-0.39131	1.473275
customer NCP	-0.100844	0.040697	-2.47792	0.018505	-0.18364	-0.01805
summer kWh	0.000421	6.82E-05	6.176039	5.75E-07	0.000282	0.00056

SUMMARY OUTPUT

4CP with kWh

Regression Statistics	
Multiple R	0.672
R Square	0.452
Adjusted R Square	0.436
Standard Error	1.2471
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*gnificance F*
Regression	1	43.63397	43.63397	28.05632	7.07E-06
Residual	34	52.87775	1.555228		
Total	35	96.51172			

	Coefficients	*andard Err*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.15201	0.46191	0.329092	0.744105	-0.7867	1.090724
summer kWh	0.000340	6.42E-05	5.296822	7.07E-06	0.00021	0.000471

SUMMARY OUTPUT

4CP with NCP

Regression Statistics	
Multiple R	0.064
R Square	0.004
Adjusted R Square	(0.025)
Standard Error	1.6813
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*gnificance F*
Regression	1	0.397889	0.397889	0.140752	0.709865
Residual	34	96.11383	2.826877		
Total	35	96.51172			

	Coefficients	*andard Err*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	2.16235	0.543292	3.980087	0.000343	1.058248	3.266453
customer NCP	0.01939	0.051696	0.375169	0.709865	-0.08566	0.124454

SUMMARY OUTPUT

Dependent Variable: Class MDD
with NCP and kWh

Regression Statistics	
Multiple R	0.654
R Square	0.428
Adjusted R Square	0.393
Standard Error	1.8825
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*gnificance F*
Regression	2	87.56291	43.78145	12.35376	9.89E-05
Residual	33	116.9513	3.543979		
Total	35	204.5142			

	Coefficients	*andard Err*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	1.8370022	0.742183	2.475133	0.018627	0.327019	3.346985
customer NCP	-0.09045	0.065914	-1.37223	0.179247	-0.22455	0.043654
summer kWh	0.0005357	0.00011	4.851823	2.85E-05	0.000311	0.00076

SUMMARY OUTPUT

Class MDD with kWh

Regression Statistics	
Multiple R	0.629
R Square	0.396
Adjusted R Square	0.378
Standard Error	1.9068
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*gnificance F*
Regression	1	80.88951	80.88951	22.24671	3.99E-05
Residual	34	123.6247	3.636021		
Total	35	204.5142			

	Coefficients	*andard Err*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	1.48812	0.706274	2.107001	0.042572	0.052799	2.923442
summer kWh	0.000463	9.82E-05	4.716642	3.99E-05	0.000264	0.000663

Class MDD with NCP

Regression Statistics	
Multiple R	0.142
R Square	0.020
Adjusted R Square	(0.009)
Standard Error	2.4276
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*gnificance F*
Regression	1	4.136975	4.136975	0.701962	0.407977
Residual	34	200.3773	5.893449		
Total	35	204.5142			

	Coefficients	*andard Err*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	3.89999	0.784449	4.971629	1.87E-05	2.305797	5.494182
customer NCP	0.06254	0.074643	0.837832	0.407977	-0.08915	0.214232

WM-9 Excerpt from Prepared Testimony of Garrick F. Jones and William Perea Marcus in California Public Utilities Commission Application 15-04-012 (July, 2016)

Marginal Cost, Revenue Allocation and Rate Design Policy Issues for San Diego Gas and Electric Company

Prepared testimony of
Garrick F. Jones
William Perea Marcus

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on behalf of
Utility Consumers Action Network

California Public Utilities Commission
Application 15-04-012

July 5, 2016

VI. Rate Design Policy – Demand Charges

One key aspect of rate design policy is that SDG&E believes that demand costs should be collected in demand charges. SDG&E witness Ms. Fang says the following about generation and distribution capacity costs.

> Distribution Demand Costs – SDG&E incurs these costs independent of energy usage. These costs are incurred on the basis of local capacity needs to meet the combined maximum demand of customers served off of a given circuit. These costs are best recovered on non-coincident demand ("NCD"), distribution demand costs should be recovered in a NCD charge ($/NCD – kW).
>
> Generation Capacity Costs – SDG&E does not incur these costs on the basis of energy usage, but rather on the basis of meeting net peak capacity needs of the system; therefore, system capacity costs should be recovered in a demand charge consistent with the time period in which those costs occur, which is demand at the time of net system peak when SDG&E may require additional capacity ($/peak-kW).[34]

We respond to this testimony to demonstrate that the residential demand charges are not cost-based and therefore should not be pursued.

A. Problems with Demand Charges Other than their Cost Basis

Demand charges were invented in the 1890s because all that a meter could measure was the customer's non-coincident peak demand and folks in the industry, without today's computer technology that enables better analysis, simply thought that customer peaks had something to do with system-wide phenomena.

Demand charges have been made obsolete in large part by time-of-use energy rates. But utilities support them because they create revenue stability at the expense of efficient energy use. High-load factor industrial customers support them, because they gain an advantage relative to lower load factor commercial customers in the same rate classes. And there is an almost ideological belief, presented as fact by many utilities, that a cost related to system demand in some way should be charged to customers based on the customer's demand even though the nexus between customer demand and system demand is not clear at all, particularly for the residential class. Thus, demand

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[34] Prepared Testimony of Cynthia Fang, pp. 14-15.

charges have persisted despite technological obsolescence. But they should not be expanded to residential customers.

Using a smart meter to deliver a residential demand charge instead of a time of use rate is like using a sophisticated video camera to take grainy snapshots.

Customers also mistrust demand charges. A recent focus group study in Ontario, Canada, where time of use (TOU) rates have been in place for several years and customers are thus fairly sophisticated, suggests that residential customers do not understand demand charges and believe that such charges are demanding perfection in their conservation efforts. The Ontario Energy Board conducted an analysis with residential focus groups that raised concerns about maximum monthly usage charges (another term for demand charges) in addition to TOU rates that Ontario customers understand:

> The concept of maximum use during peak times is difficult for people to understand and raised concern among a few. There is no template for measuring maximum use that people are used to in the way they understand TOU. It was not obvious how this would be calculated.
>
> Without precise details of this there was concern expressed by some that small lapses in their conservation efforts will mean they will have to pay a high price for that (even if they conserve diligently on the vast majority of days during peak times). So there will be questions of fairness if they have conserved on the vast majority of days during peak demand times and essentially helped to reduce peak consumption.[35]

There are a number of reasons why residential demand charges are a bad idea.

1. They blunt incentives to conserve – even during peak periods - once a maximum demand is hit. Here is a personal example. Because it was 108 degrees in the Central Valley and I had a houseguest, I ran both air conditioners in my house and clearly hit a maximum demand in the last week of June that I haven't seen in a couple of years. With a demand charge, I would have far less incentive to conserve energy – even on other hot days that stress the system which might be a little cooler or without the houseguest – because I would

[35] The Gandalf Group, Ontario Energy Board Distribution Charge Focus Groups: Final Report, October 9, 2013, p. 9.

already be tens of dollars of fixed charges in the hole and my savings from reducing energy use would be limited.

2. They require customers to keep track of random events which have no intrinsic value to anyone. Customers do not want to be rate computers, but to reduce their demand charge they need to have the following scenario in mind **every winter morning**: "My coffee-maker is running, and it's chilly so my furnace fan is running. That means I shouldn't turn on the toaster and the hair dryer at the same time at 7 am or I could get a higher demand charge. I need to wait 15 minutes to use that toaster." This kind of price signal is totally disconnected from either causation of or avoidance of utility costs. It is also a waste of the very limited amount of brainpower that most people want to spend on their electric rates. So customers will eventually screw up, pay up, and give up.
3. They give customers who are connected to gas incentives to get rid of electric stoves and ovens and electric dryers. Before bringing in a residential demand charge, an electric utility should have the obligation to inform customers them that an electric stove is one of the worst things to own if there's a demand charge – either non-coincident or peak period only, because the oven plus the air conditioner will trigger the charge. If SDG&E were in competition with an independent gas utility, which it is not, it would be handing the gas utility a great marketing plan to poach load from the electric utility because gas would be far more cost-effective by avoiding demand charges.
4. Residential demand charges have bizarre impacts on cost-effectiveness of energy efficiency to customers – which are not necessarily the same as cost-effectiveness to the utility or society. Getting a more efficient air conditioner (or even a smaller one of the same efficiency) can avoid a demand charge, but weatherizing one's house so an existing air conditioner runs less frequently but produces the same number of kilowatts when it turns on, will not reduce the customer's bills nearly as much, even if it has similar effects on system peak demand.
5. Specifically, residential non-coincident demand charges such as those proposed by SDG&E for distribution can work at cross-purposes with time-of-use energy rates. A customer does everything she can to not use peak period energy, and when the peak period is over turns on energy-consuming equipment. Bingo! High demand charge to penalize her for following the TOU price signals. And more customer confusion.

6. If a utility wants to reduce feeder loads and defer construction, a time of use rate component at times when most feeders are peaking will do a better job than a demand charge. If it wants to build as many feeders as possible to expand rate base without demand reductions getting in the way, a demand charge is the best way to build them and get customers to pay for them.

But having briefly made these points, which I will expand upon in far more detail at a later time if SDG&E actually proposes something instead of just talking about policy, I now analyze the major objection to residential demand charges. They are not cost-based.

Demand charges systematically overcharge small users. The summation of the analysis below is that residential customers using less than 300 kWh use 15% less demand per unit of energy than the system average but would pay 27% more demand charges that the system average. Residential customers using over 1000 kWh use approximately the same amount of demand per unit of energy as the system average but would pay 32% less demand charges per unit of energy than the system average. The large customers are subsidized by the small customers. Demand charges (or other fixed charges for costs that vary with usage) are Robin Hood in reverse.

The Commission should reject residential demand charges out of hand for creating intra-class subsidies of big users, before even thinking about dealing with the rest of the problems caused by their implementation that I discussed above.

B. Some Key Concepts in Analyzing Demand Charges

Critical concepts in analyzing demand charges are load diversity and coincidence.

Load diversity reflects the fact that the utility does not expect to experience the maximum NCP load of each individual customer at the same time, on parts of the system that do not serve a single customer (i.e., all parts of the system other than service lines to an individual customer and specific transformers that serve one single customer). As a result, the utility does not need to build most of its system to meet the sum of each customer's NCP. The system becomes more diverse (i.e., the load that the system must carry becomes a smaller fraction of the sum load of the individual customers) as more customers are aggregated. SDG&E's engineering manuals suggest that load diversity even for sizing transformers is 70% for single-family customers with air conditioning, 60% for multi-family customers with air conditioning, and 50% for customers without air conditioning.[36] Thus, at the level of the transformer, 30-50% of the individual customer's non-coincident peak load is diversified away in SDG&E's own engineering analysis, which is likely to be conservative to prevent overloads.

Coincidence is related to the concept of load diversity, which can be examined at the level of the individual customer, the entire rate class, or subsets of the class.

The analysis involves a comparison of the customer's own maximum demand with estimated generation or distribution demands available for those same customers. While recognizing that generation demand is allocated over a large number of hours, this analysis used the four coincident peak hours in the months of July-October (4CP) because those data sets were readily available from SDG&E's load data. We analyzed distribution demand on a system-wide basis using SDG&E's load research sample based on the Class Peak demand, given that feeders and substations serving residential customers peak later in the day than the system peak and closer to the residential class' own peak. We also conducted a review of the extent to which the customer's NCP, when combined with energy in the relevant time period, explains the customer's Class peak or 4CP demand.

The coincidence factor is thus the generation or distribution demand divided by the customer's NCP demand. The NCP demand can be calculated as the maximum demand in the year, or alternatively as the average maximum demand on a monthly basis (how a demand charge in equal dollars in every month would be calculated). The customer NCP demands will always be larger than the more diversified demands at 4CP or Class Peak. So the coincidence factor is always less than one. The lower the coincidence factor, the worse the sum of customer NCPs (and thus a demand charge) will be in actually matching up with the demand-related costs that the utility is proposing to collect through NCP demand.

The questions required to analyze the cost basis of demand charges are (1) whether the customer NCP has a systematic bias (i.e., smaller or lower load factor customers have a lower coincidence with generation or distribution demand than larger or higher load factor customers), (2) whether there are large amounts of variation in the coincidence among customers of the same size (so that

[36] UCAN DR 2-39, Residential Demand Estimating, Table 3, fourth page.

the coincidence is so variable that it cannot be used to establish a demand charge without harming large numbers of customers by charging them rates that are not cost-based), and (3) whether the generation and distribution demand costs can be better predicted by energy use in a relevant time period than by maximum customer NCP demand in the same time period. To the extent that energy use is a better predictor of Class Peak or 4CP than maximum NCP demand, a demand charge is a less accurate and more crude method of setting rates than an energy charge, which may include time-of-use components. The third question is answered by use of regression equations, which I discuss further below.

C. Using Load Research Data to Analyze Coincidence and Determine Whether Residential Demand Charges Are Cost-Based for SDG&E.

SDG&E's load research data for the Rate DR class was analyzed by breaking the residential class into groupings by average monthly usage and by comparing average usage to various measures of demand (the average 4CP (July-October) as a shorthand way to analyze generation demand, the class peak demand (for distribution demand), and the customer's own NCP measured in two ways – the maximum demand at any time in the year and the average of the 12 maximum demands in each month – which would be the basis for a demand charge). Coincidence of the NCP demand with Class Peak and 4CP and differences in load factor[37] by size of customers were computed.[38] The four figures below present data from SDG&E's load study for the residential class as a whole. Attachment 6 contains the aggregated data used to construct them.

[37] The load factor is the average load divided by the peak load being measured.

[38] From SDG&E's response to UCAN DRs 2-2 and 2-3. To conduct the analysis, I excluded customers with less than 50kWh in one month and customers whose minimum monthly consumption was less than 15% of the maximum monthly consumption to try to screen out customers with partial year data, and other customers whose load patterns changed dramatically in the middle of the year. This removed some solar customers but also screened out customers with bad data. I also excluded customers with missing demand data, even though energy data existed for them. Finally, five cases were removed where the maximum demand during the year was less than the average demand during the year, which is a physical impossibility and must result from some kind of data error.

Figure 1: Energy and Demand by Size of SDG&E Residential Customer

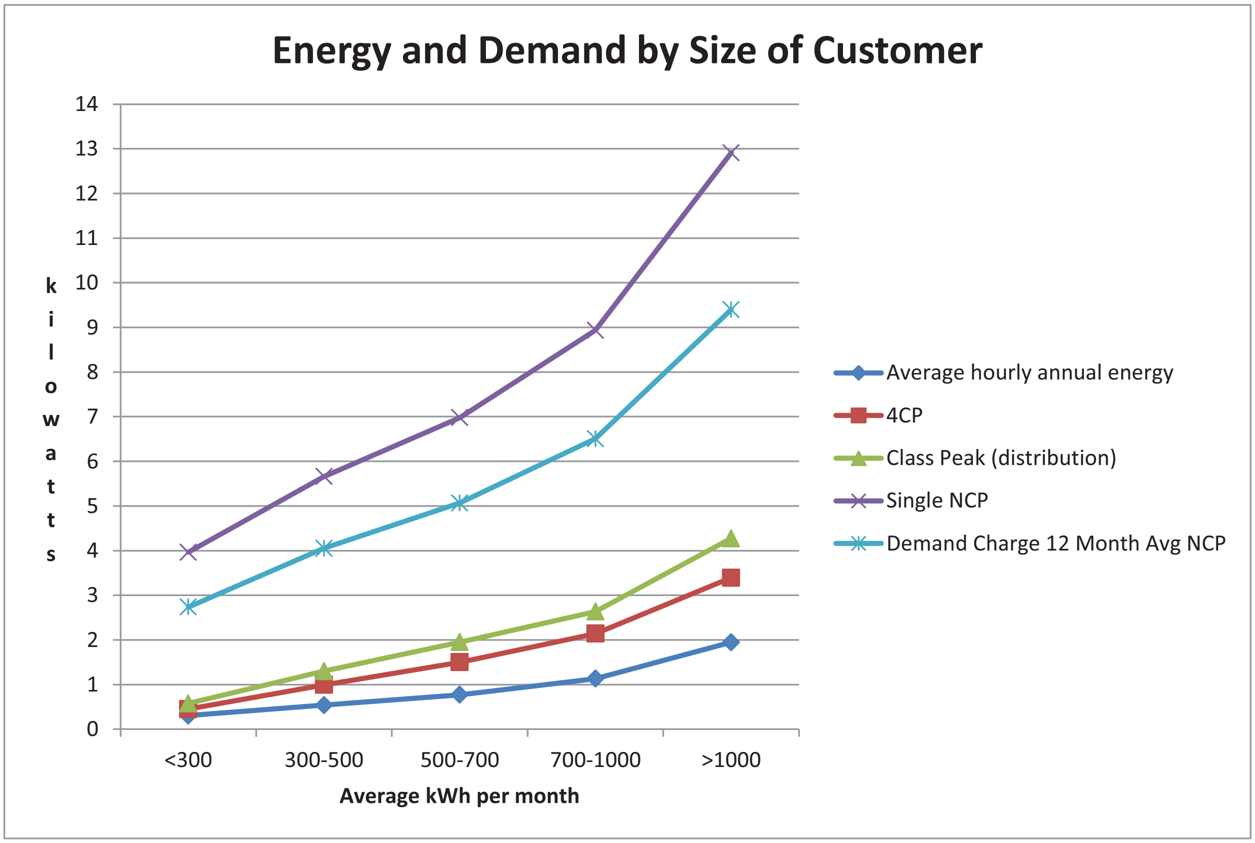

Figure 1shows the loads for residential customers of different size groups. SDG&E's strata were used to weight the specific customers in each group. It shows that from the smallest to the largest customers, energy use rises by 6.4 times, 4CP system peak rises 7.5 times, the MDD rises 7.4 times, but the NCP rises only 3.2 times based on the maximum throughout the year and 3.4 times based on the 12-month average on which demand charges are based.

Figure 2: Load Factors by Size of Residential Customer

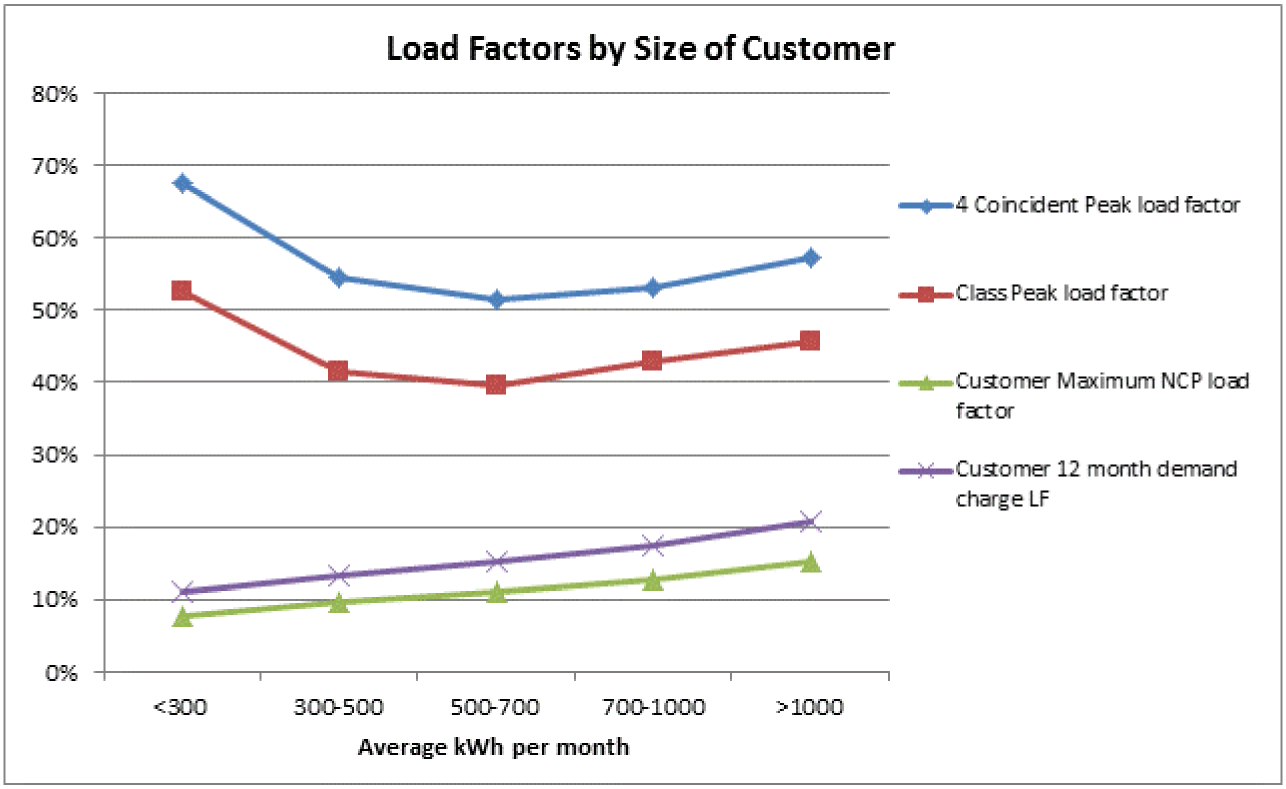

Figure 2 shows that the system load factors (4CP and Class Peak) are highest for the smallest customers and otherwise relatively constant across size ranges, except that the very largest customers have slightly better load factors than the mid-range. If the system load factors of smaller customers are the same as for larger customers, then the demand-related cost of service for those customers is approximately equal per kWh to larger customers. In the case of SDG&E, smaller customers have slightly better load factors than larger customers which would mean that their costs of generation, transmission, and distribution capacity per kWh of energy are actually lower than for larger customers. In any event, it is the system load factors that are important in determining the costs of serving customers.

The NCP load factor goes up as usage increases. But the NCP load factor—although the basis for a demand charge—is irrelevant to how the system as a whole is planned and operated. Therefore, assigning higher costs to customers with lower NCP load factors – which is what a demand charge does – is not cost-based if the underlying system load factors are similar or if small customers have better system load factors.

Figure 3: Coincidence by Size of Residential Customer

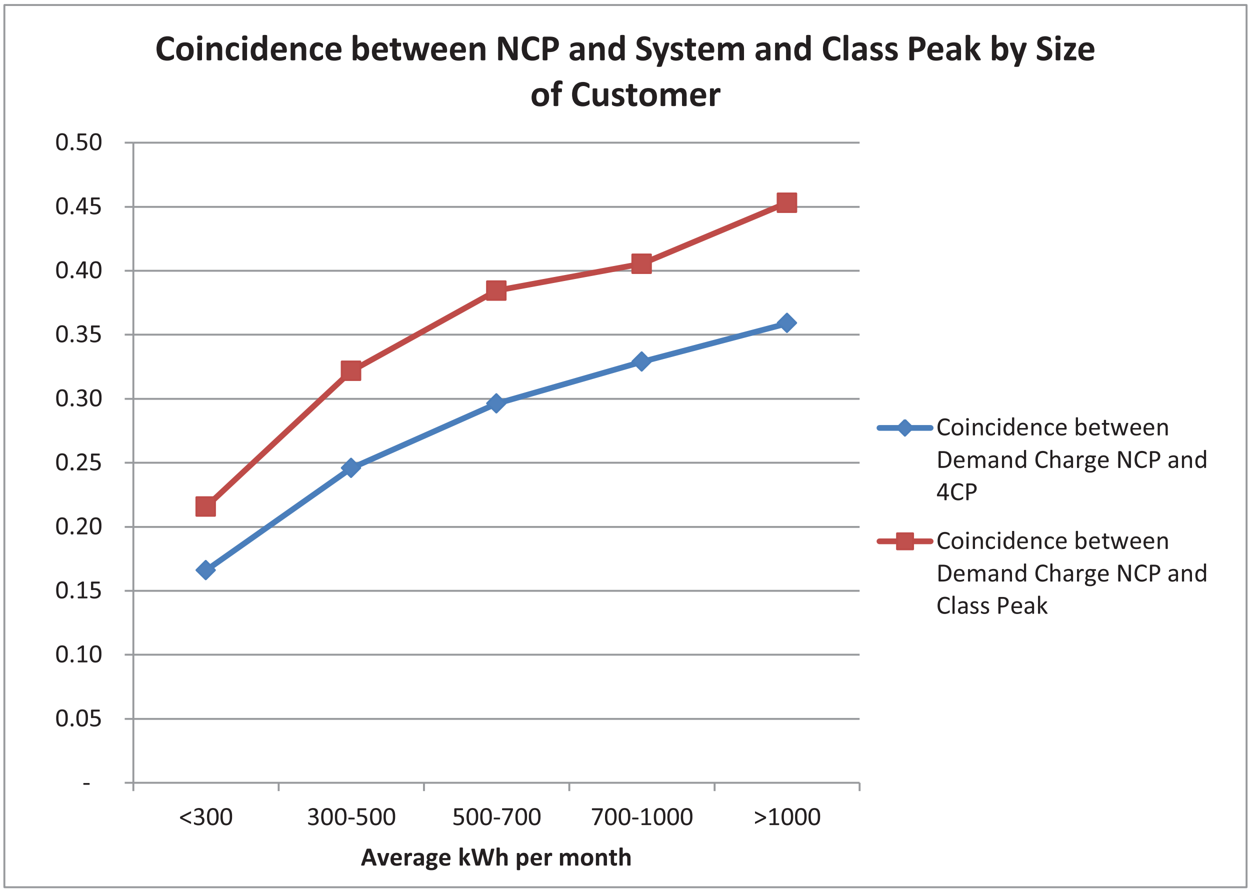

Figure 3puts it all together and looks at the coincidence between NCP and system peaks. It indicates that demand charges are highly problematic. The coincidence factors are not figures like 80% (as observed for large commercial and industrial customers with load factors above 40% in the load research studies provided to UCAN in response to DR 2-1 and other studies that I have reviewed) but are no higher than 50%. Thus, there is considerably more variation in customer NCP demand for residential customers than for non-residential customers. Moreover, coincidence is much lower for small residential customers than for large ones. Thus, using a maximum demand charge to collect demand costs will systematically overcharge small customers and undercharge larger customers on the SDG&E system.

Figure 4: Demand Costs and Charges, Relative to Class Average by Size of Residential Customer

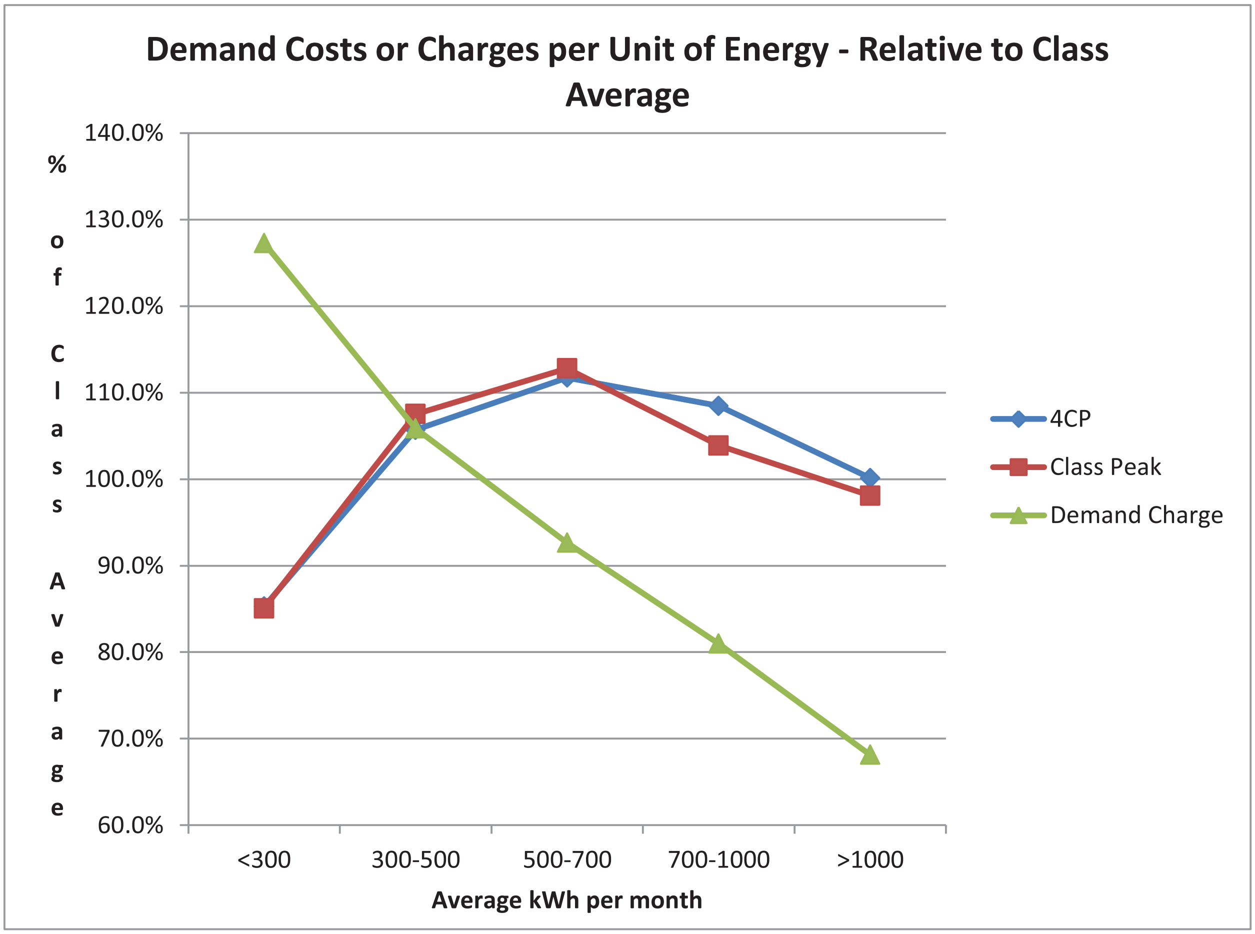

Figure 4 summarizes everything that is wrong with residential demand charges from a cost of service point of view. A residential customer using less than 300 kWh imposes approximately 15% less than the system average demand <u>costs</u> (measured by 4CP or class peak) per unit of energy but would pay 27% more demand <u>charges</u> per unit of energy than the system average. Similarly, the average customer using more than 1000 kWh has about a system average level of demand per unit of energy (101% of 4CP and 98% of class peak), while paying a demand charge that is 32% less than the system average. Thus demand charges on the SDG&E system would subsidize large customers at the expense of small ones.

D. Individual Residential Customers vs. Mobile Home Parks: An Example of Coincidence and Diversity

Finally, we can examine why individual residential customers' demand charges do not adequately reflect coincidence and diversity by comparing rate DR to rate DT (master metered mobile home parks). The chart below makes that comparison from SDG&E's 2013 load research data.

Table 16: Comparison of 2013 load characteristics of Individual Residential Customers and Master-Metered Mobile Home Parks

	Rate DR	Rate DT
Average number of customers	1,238,263	437
Annual Energy	7,142,254,160	155,111,564
Average hourly use	815,326	17,707
4CP	1,523,275	34,905
Class Peak	1,896,040	48,278
Demand Charge (12 NCP)	5,452,000	37,318
load factor		
4CP	54%	51%
Class Peak	43%	37%
Demand Charge (12 NCP)	15%	47%
coincidence of demand charge with		
4CP	0.28	0.94
Class Peak	0.35	1.29

The kW of noncoincident demand collected in demand charge (average of customer's NCP across the entire year) for a Rate DR customer is 3.6 times the 4CP demand and 2.9 times the class peak demand. For a Rate DT customer, the demand collected through a demand charge is 1.1 times the 4CP demand and is actually less than 0.8 times the class peak demand – a very different level of coincidence and diversity. The reason is that the demand measured at the mobile home park is a diversified demand of its residents, not the sum of each individual resident (as it would be with Rate DR).[39] Therefore, the coincidence of a demand charge paid by a mobile home park is much

[39] The 2013 load research data shows an average of 437 DT customers. We can estimate the average mobile home park served with electricity has somewhere between 50-70 spaces based on usage per park and usage per Rate DR residential customer. We unfortunately cannot provide a more precise estimate because SDG&E never in its workpapers included the number of spaces subject to the space discount in its billing determinants – unlike both of the other electric utilities in the state and unlike its own gas department's TCAP filing (where 239 GT customers served 27,189 spaces or 114 spaces per customer). We realized that this routine information was missing too late to

higher than for each individual residential customer, because the load is diversified across a large number of customers for each Rate DT meter. The load subject to the demand charge for the residential class as a whole would be 4.4 kW per customer. For master-metered mobile home parks, it is only 1.2 to 1.7 kW per customer (based on 50-70 customers per park). This illustrates the very large amount of diversity between one residential customer and a large number served through a single meter.

E. Regression Analyses to Show that Demand is More Related to Energy than Customers' Own Non-Coincident Peaks.

Ms. Fang stated that distribution and generation costs are "independent of energy usage."[40] Well actually they may not be. Energy usage appears to be a better measure of the demands that cause generation and distribution plant to be built than the customers' own non-coincident peaks. We used regression analysis to show this point.

I conducted a regression analysis relating 4CP and Class Peak to customers' summer energy use (July-October) and to maximum NCP summer demand. A regression equation is a statistical method of fitting a dependent variable (in this case 4CP or Class Peak) to one or more other independent variables to determine the best fit and the coefficients associated with each variable that give the least amount of variation (measured by the least squared error). A regression equation is more detailed than a simple coincidence analysis, as it takes into account all of the individual data points representing individual observations. In this specific case, the dependent variable was the measure of system peak (4CP or Class Peak). The two independent variables used (separately or in combination) were the customer NCP in the four summer months and kWh usage in the four-month summer period. Attachment 7 shows the equations.

For residential customers, NCP demand is a worse variable for explaining CP demand than energy use. Energy use by itself explained 57% of the variation in average 4CP demand, while NCP demand by itself explained only 44%. In other words, if an analyst were to choose only one variable to explain 4CP loads (or Class peak loads), NCP demand is a worse variable to pick than summer energy use. Using both variables, 61% of the variation was explained, but most of the

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submit a data request that could be answered in time for this filing. We have requested this information and will update these calculations when we receive it.

[40] Testimony of SDG&E witness Cynthia Fang, p. CF-15

variation was explained by differences in energy use. While the NCP variable was statistically significant it only had a coefficient of 0.098 (i.e., after considering energy, only 9.8% of NCP was related to 4CP).

For Class MDD, the relationships were less strong but similar. NCP demand was still a weaker variable. Energy use by itself explained 37% of the variation in Class peak, while NCP demand explained only 33%. Again, NCP would be a worse choice for a single variable. Using both variables, 42% of the variation was explained, and NCP was statistically significant but again only had a coefficient of 0.17, showing slightly more explanatory power than the 4CP equation but still relatively weak.

This information also suggests that demand charges for generation and transmission and distribution should not be used for residential customers. The NCP variable has only a weak explanatory power when examining both 4CP and class peak. The biases and problems with difference in coincidence by size of customer discussed overcome any weak explanatory power that such a variable might have.

F. Conclusion

As a matter of policy, demand charges should not be pursued. They are not cost-based because there is a large variation in the coincidence of NCP demand for residential customers, which can be driven by random fluctuations, particularly when measured on a short interval, with coincident peak demand and the class coincident peak. In addition, small customers have a higher NCP demand (caused by randomly turning on equipment) as compared to their coincident peak demands or class peak. This means that using a demand charge to collect either generation or distribution costs will systematically overcharge the average of small residential customers. Demand charges are not cost based for residential customers because they cause small customers to subsidize larger ones. If the utility wants to try to reduce generation peaks or substation and feeder peaks in residential areas, time-of-use rates will support that outcome better than crude 1890s rate design.

VII. Overall Conclusion

As noted in the detailed analysis provided by UCAN above, in addition to not pursuing demand charges for the residential class, whether the Commission chooses to apply the rental method or the NCO method for customer related costs, the Commission should use the estimates provided by UCAN. Also, given the significant concerns with SDG&E's allocation data there should be a 1.5% cap on rate increases to prevent significant increases that may arise from all of the moving of goal posts for generation and distribution costs. Finally, the Commission should reject SDG&E's three-year path to equal percent of marginal cost.

List of Attachments

Attachment 1:	Qualifications of Garrick F. Jones
Attachment 2:	Qualifications of William Perea Marcus
Attachment 3:	Excerpts from Testimony of Sara Franke in A. 14-11-003
Attachment 4:	Excerpt from SDG&E 2014 FERC Form 1 (Accounts 586 and 587)
Attachment 5:	Excerpt from SCE-2 in App. 14-06-014 (estimation of feeder and substation demand from customer demand)
Attachment 6:	Demand, Load Factors, and Coincidence by Size of Residential Customer
Attachment 7:	Regression Equations Regarding Relationship of Energy Use, Customer NCP Demands, and System and Class Peaks

Attachment 6: Demand, Load Factors, and Coincidence by Size of Residential Customer

SDG&E Rate DR Customer Demands, Load Factors, and Coincidence by Size of Customer

						Single NCP		Average 12 NCP (Demand Charge)	
Monthly energy grouping	Average kWh per year	Average 4CP load factor	Class Peak load factor	Single NCP load factor	Average 12 NCP load factor	Coincidence with system 4CP	Coincidence with class peak	Coincidence with system 4CP	Coincidence with class peak
<200	1,930	75.0%	62.5%	7.1%	10.5%	0.094	0.113	0.140	0.167
200-300	3,019	63.6%	47.5%	7.9%	11.4%	0.125	0.167	0.179	0.240
300-400	4,176	55.8%	42.8%	9.1%	12.7%	0.163	0.212	0.228	0.296
400-500	5,388	52.6%	40.0%	10.1%	14.0%	0.192	0.252	0.267	0.351
500-600	6,546	51.5%	39.6%	10.9%	15.0%	0.211	0.275	0.292	0.380
600-700	7,063	51.1%	39.5%	11.3%	15.5%	0.220	0.285	0.302	0.391
700-800	8,999	52.0%	43.9%	12.3%	17.0%	0.237	0.281	0.326	0.387
800-1000	10,676	53.8%	42.3%	13.0%	17.8%	0.242	0.307	0.331	0.420
1000-1250	13,376	55.5%	41.0%	13.4%	18.5%	0.241	0.325	0.333	0.450
1250-1500	16,319	54.8%	46.5%	14.8%	20.3%	0.270	0.318	0.370	0.435
1500-2000	20,532	59.8%	51.3%	17.3%	23.4%	0.288	0.337	0.391	0.456
>2000	34,292	69.7%	57.8%	21.6%	29.6%	0.311	0.374	0.426	0.513
<300	2,657	67.4%	52.5%	7.7%	11.1%	0.11	0.15	0.17	0.22
300-500	4,732	54.3%	41.5%	9.5%	13.3%	0.18	0.23	0.25	0.32
500-700	6,763	51.4%	39.5%	11.0%	15.2%	0.22	0.28	0.30	0.38
700-1000	9,929	53.0%	43.0%	12.7%	17.4%	0.24	0.30	0.33	0.41
>1000	17,043	57.3%	45.4%	15.0%	20.7%	0.26	0.33	0.36	0.45
whole system	6,084	57.4%	44.6%	10.1%	14.1%	0.18	0.23	0.25	0.32

Attachment 7: Regression Equations Regarding Relationship of Energy Use, Customer NCP Demands, and System and Class Peaks

SUMMARY OUTPUT

Dependent Variable 4CP System Peak
Independent Variable - Summer Energy Only

Regression Statistics	
Multiple R	0.7576
R Square	0.5739
Adjusted R Square	0.5738
Standard Error	0.8244
Observations	6568

ANOVA

	df	SS	MS	F	Significance F
Regression	1	6,009.65	6,009.65	8,843.31	-
Residual	6566	4,462.06	0.68		
Total	6567	10,471.71			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	0.09591	0.01644	5.83	0.00000	0.06368	0.12815
summer kWh	0.0005917	0.0000063	94.04	-	0.00058	0.00060

SUMMARY OUTPUT

Dependent Variable 4CP System Peak
Independent Variable - Summer NCP Only

Regression Statistics	
Multiple R	0.6598
R Square	0.4353
Adjusted R Square	0.4352
Standard Error	0.9490
Observations	6568

ANOVA

	df	SS	MS	F	Significance F
Regression	1	4,558.31	4,558.31	5,061.36	-
Residual	6566	5,913.41	0.90		
Total	6567	10,471.71			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	(0.11565)	0.02322	(4.98)	0.00000	(0.16116)	(0.07013)
Max NCP Summer	0.25218	0.00354	71.14	-	0.24523	0.25913

SUMMARY OUTPUT

Dependent Variable 4CP System Peak
Independent Variables
Summer Energy
Summer NCP

Regression Statistics	
Multiple R	0.7787
R Square	0.6064
Adjusted R Square	0.6063
Standard Error	0.7923
Observations	6568

ANOVA

	df	SS	MS	F	Significance F
Regression	2	6,350.17	3,175.09	5,057.43	-
Residual	6565	4,121.54	0.63		
Total	6567	10,471.71			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	(0.16652)	0.01941	(8.58)	0.00000	(0.20457)	(0.12847)
summer kWh	0.0004532	0.0000085	53.42	-	0.00044	0.00047
Max NCP Summer	0.09668	0.00415	23.28934	0.00000	0.08854	0.10481

SUMMARY OUTPUT

Dependent Variable Annual Class Peak
Independent Variable - Summer Energy Only

Regression Statistics	
Multiple R	0.6116
R Square	0.3740
Adjusted R Square	0.3739
Standard Error	1.5415
Observations	6568

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	9,321.72	9,321.72	3,923.01	-
Residual	6566	15,601.89	2.38		
Total	6567	24,923.61			

	Coefficients	*tandard Erro*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.16290	0.03075	5.30	0.00000	0.10263	0.22318
summer kWh	0.0007369	0.0000118	62.63	-	0.00071	0.00076

SUMMARY OUTPUT

Dependent Variable Annual Class Peak
Independent Variable - Summer NCP Only

Regression Statistics	
Multiple R	0.5747
R Square	0.3303
Adjusted R Square	0.3302
Standard Error	1.5944
Observations	6568

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	8,232.87	8,232.87	3,238.74	-
Residual	6566	16,690.74	2.54		
Total	6567	24,923.61			

	Coefficients	*tandard Erro*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	(0.24106)	0.03901	(6.18)	0.00000	(0.31754)	(0.16459)
Max NCP Summer	0.33891	0.00596	56.91	-	0.32724	0.35059

SUMMARY OUTPUT

Dependent Variable Annual Class Peak
Independent Variables
Summer Energy
Summer NCP

Regression Statistics	
Multiple R	0.6449
R Square	0.4159
Adjusted R Square	0.4157
Standard Error	1.4891
Observations	6568

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	10,365.53	5,182.77	2,337.18	-
Residual	6565	14,558.08	2.22		
Total	6567	24,923.61			

	Coefficients	*tandard Erro*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	(0.29656)	0.03648	(8.13)	0.00000	(0.36808)	(0.22505)
summer kWh	0.000494	0.000016	31.01	0.00000	0.00046	0.00053
Max NCP Summer	0.16926	0.00780	21.70	0.00000	0.15397	0.18455

WM-10 Southern California Edison Load Research Sample – Handout for Western Conference of Public Service Commissioners conference, June, 2015

Southern California Edison 2012 Load Research Sample

Small customers have low coincidence between their own peaks and system peak. They also have better load factors and a lower use of on-peak energy. These customers are concentrated in multi-family buildings. Table 1 shows the results by absolute usage. Table 2 shows the results for small, medium and large customers adjusted for climate using California's baseline quantities.

Table 1: Edison Load Research Sample by Quantity of Summer Electricity Use

	Single-Family Customers						
Average monthly summer use	<250	250-500	500-750	750-1000	1000-1500	>1500	All
customers	163,316	585,253	548,091	342,672	310,444	156,170	2,105,946
percent of customers	7.8%	27.8%	26.0%	16.3%	14.7%	7.4%	100.0%
summer on-peak use	29.8	76.1	133.1	190.0	290.5	478.4	167.3
summer average use	165.4	378.9	615.9	855.1	1,208.3	1,928.6	738.7
% summer use on-peak	18.0%	20.1%	21.6%	22.2%	24.0%	24.8%	22.7%
winter av	188.2	376.1	535.4	684.1	882.9	1,204.0	589.2
annual average use	180.6	377.0	562.3	741.1	991.4	1,445.5	639.0
average CP	0.33	1.39	2.33	3.19	4.43	5.57	2.60
CP load factor	75.5%	37.2%	33.0%	31.9%	30.7%	35.5%	33.6%
average NCP	3.33	4.38	5.66	6.70	8.38	10.79	6.08
NCP load factor	**7.4%**	**11.8%**	**13.6%**	**15.1%**	**16.2%**	**18.4%**	**14.4%**
CP coincidence	**9.8%**	**31.7%**	**41.2%**	**47.5%**	**52.8%**	**51.6%**	**42.8%**
	Multi-Family Customers						
Average monthly summer use	<250	250-500	500-750	750-1000	1000-1500	>1500	All
customers	537,001	667,621	299,343	104,613	76,181	31,487	1,716,247
percent of customers	31.3%	38.9%	17.4%	6.1%	4.4%	1.8%	
summer on-peak use	29.6	71.9	132.8	184.6	302.4	433.4	93.6
summer average use	159.5	363.6	601.7	832.2	1,213.5	1,846.2	437.2
% summer use on-peak	18.6%	19.8%	22.1%	22.2%	24.9%	23.5%	21.4%
winter av	179.1	329.8	462.5	586.4	718.4	1,096.6	354.3
annual average use	172.5	341.1	508.9	668.3	883.4	1,346.5	381.9
average CP	0.45	1.05	1.86	2.76	3.64	4.64	1.29
CP load factor	**53.0%**	**44.4%**	**37.5%**	**33.2%**	**33.2%**	**39.8%**	**40.5%**
average NCP	2.48	3.64	4.85	6.31	8.17	9.96	4.00
NCP load factor	9.5%	12.8%	14.4%	14.5%	14.8%	18.5%	13.1%
CP coincidence	**18.0%**	**28.9%**	**38.3%**	**43.7%**	**44.6%**	**46.6%**	**32.3%**
	All customers - single-plus multi-family						
Average monthly summer use	<250	250-500	500-750	750-1000	1000-1500	>1500	All
customers	700,317	1,252,874	847,435	447,286	386,625	187,657	3,822,193
percent of customers	18.3%	32.8%	22.2%	11.7%	10.1%	4.9%	100.0%
summer on-peak use	29.6	74.2	133.0	189.1	292.3	471.1	136.0
summer average use	160.8	371.6	611.2	850.8	1,208.5	1,917.4	609.6
% summer use on-peak	18.4%	20.0%	21.8%	22.2%	24.2%	24.6%	22.3%
winter av	181.2	353.3	514.7	667.5	853.3	1,188.4	489.7
annual average use	174.4	359.4	546.8	728.6	971.7	1,431.4	529.6
average CP	0.42	1.24	2.19	3.08	4.29	5.42	2.06
CP load factor	57.5%	39.8%	34.2%	32.4%	31.0%	36.2%	35.2%
average NCP	2.68	4.01	5.45	6.63	8.31	10.65	5.21
NCP load factor	8.9%	12.3%	13.7%	15.1%	16.0%	18.4%	13.9%
CP coincidence	**15.5%**	**30.8%**	**40.2%**	**46.6%**	**51.7%**	**50.9%**	**39.5%**

Table 2: Edison Load Research Sample Adjusted for Climate – Percentage of Baseline Use

	Single-Family Customers			
Average monthly summer use	<130% BL	130-200% BL	>200% BL	All
customers	727,678	649,798	728,471	2,105,946
customer %	34.6%	30.9%	34.6%	100.0%
summer on-peak use	77.8	136.7	257.7	158.2
summer average use	373.0	654.1	1,179.4	769.3
% summer use on-peak	20.9%	20.9%	21.8%	20.6%
winter average use	336.3	539.4	886.3	613.7
annual average use	348.5	577.6	984.0	665.6
average CP	1.30	2.47	4.03	2.71
CP load factor	**36.7%**	**32.1%**	**33.5%**	**33.6%**
average NCP	4.50	5.51	8.16	6.33
NCP load factor	**10.6%**	**14.4%**	**16.5%**	**14.4%**
NCP coincidence	28.9%	44.8%	49.3%	42.8%
	Multi-Family Customers			
Average monthly summer use	<130% BL	130-200% BL	>200% BL	All
customers	1,179,492	381,280	175,646	1,736,418
	67.9%	22.0%	10.1%	100.0%
summer on-peak use	60.3	127.8	232.5	92.5
summer average use	293.4	599.8	1,050.1	437.3
% summer use on-peak	20.7%	21.4%	22.1%	22.1%
winter average use	265.8	500.4	826.6	374.1
annual average use	275.0	577.6	901.1	404.8
average CP	0.88	1.67	3.03	1.27
CP load factor	**42.8%**	**47.4%**	**40.8%**	**43.6%**
average NCP	3.73	5.36	7.57	4.48
NCP load factor	**10.1%**	**14.8%**	**16.3%**	**12.4%**
NCP coincidence	**23.6%**	**31.2%**	**40.0%**	**28.4%**
	All customers - single-plus multi-family			
Average monthly summer use	<130% BL	130-200% BL	>200% BL	All
customers	1,907,170	1,031,078	904,117	3,842,364
percent of customers	49.6%	26.8%	23.5%	100.0%
summer on-peak use	67.0	133.4	252.8	100.4
summer average use	323.8	634.0	1,154.3	475.9
% summer use on-peak	20.7%	21.0%	21.9%	21.1%
winer average use	292.7	525.0	874.7	402.6
annual average use	303.08	577.63	967.90	430.6
average CP	1.04	2.17	3.83	1.57
CP load factor	**39.9%**	**36.4%**	**34.6%**	**37.5%**
average NCP	4.03	5.45	8.04	4.75
NCP load factor	**10.3%**	**14.5%**	**16.5%**	**12.4%**
NCP coincidence	**25.8%**	**39.8%**	**47.6%**	**33.1%**

And a couple of charts and graphs using the whole sample. NCP load starts high and rises slowly. CP load tends to rise as fast or faster than average hourly load. (Charts 1 and 2)

Chart 1: Loads and Summer Use

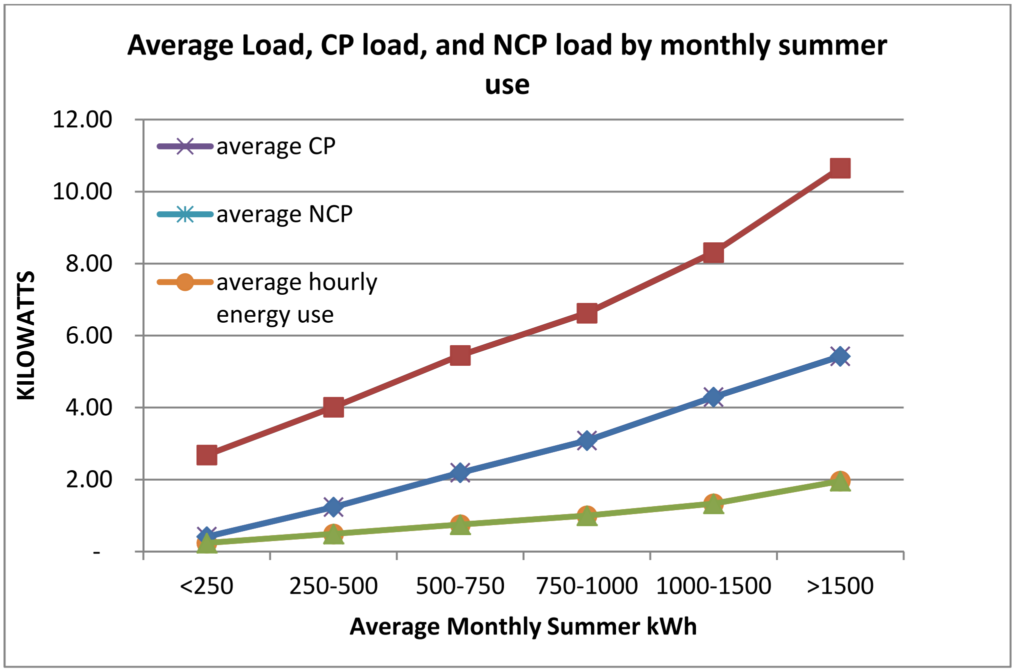
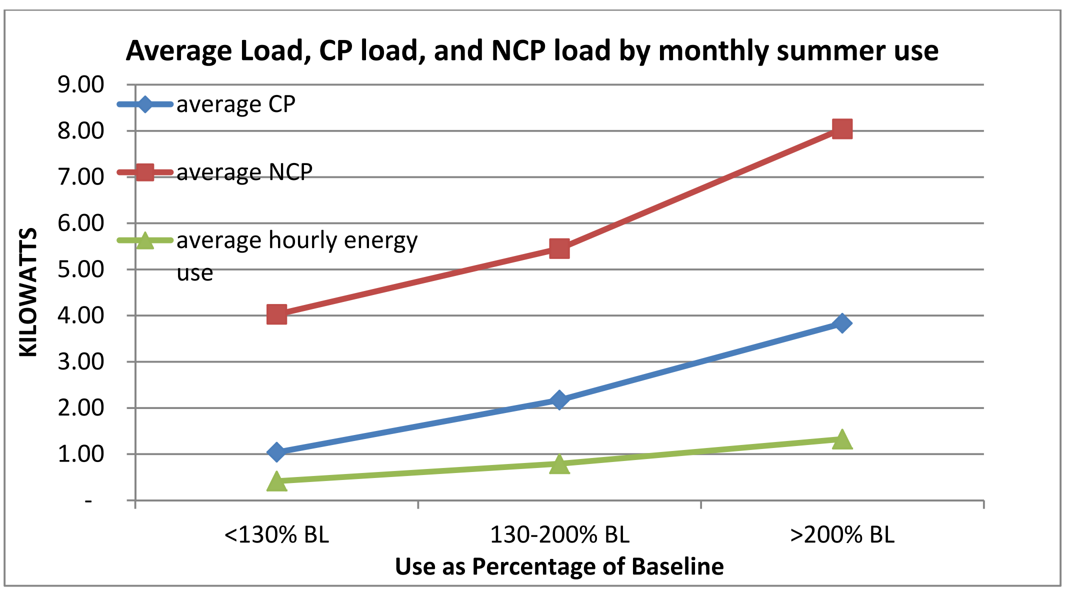


Chart 2: Loads and Summer Use



About half of Edison's customers use less than 500 kWh and half of Edison's customers use less than 130% of baseline (coincidental facts). These customers have higher load factors (measured against coincident peak loads), lower load factors (measured against NCP loads) and MUCH LOWER COINCIDENCE between their NCP loads and their peak loads than do larger users. Charging small customers the same demand charge as larger users will systematically and knowingly overcharge them on the Edison system, because of differences in coincidence.

Other Edison data support this fact. Edison has found when calculating diversity from the customer to feeder and substation loads that apartments have a diversity factor from NCP to feeder or substation peak of about 25 percent, while the diversity factor of single-family homes is around 35 percent.

Charts 3 and 4 present the data.

Chart 3: Load Factor and CP/NCP Coincidence by Customer Size

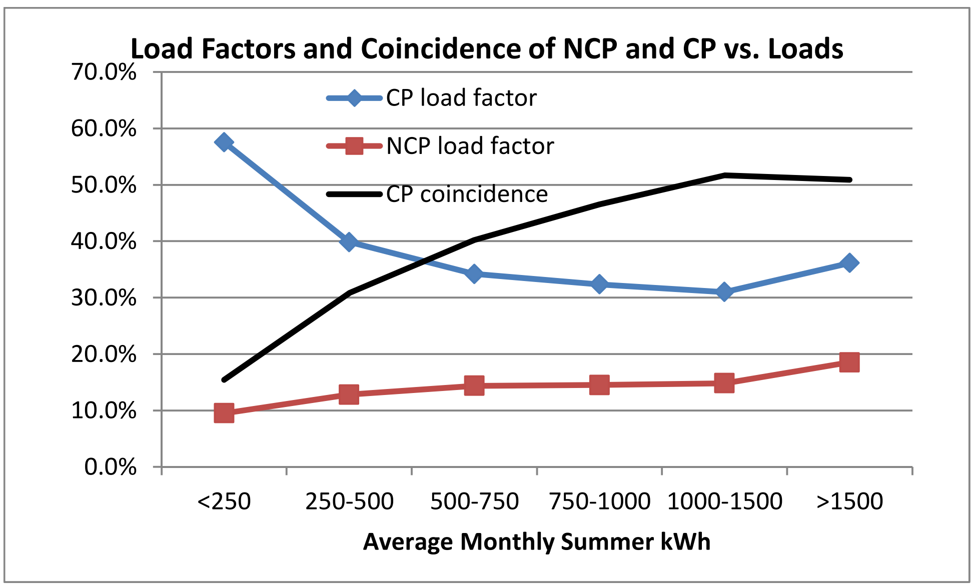
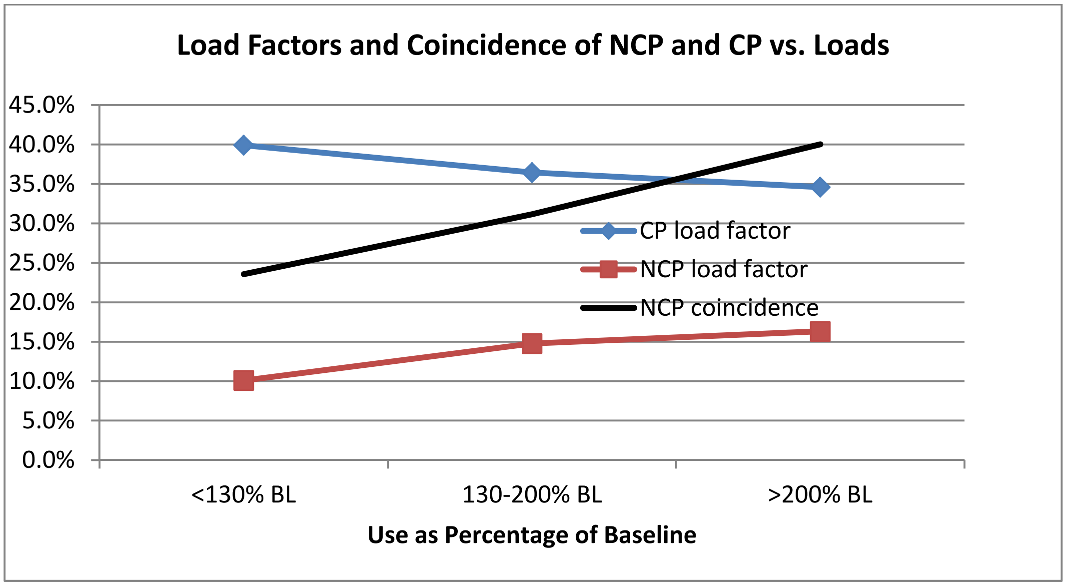


Chart 4: Load Factor and CP/NCP Coincidence by Customer Baseline Use



<u>CERTIFICATE OF SERVICE</u>

I, Shawn McMurray, hereby certify that on January 31, 2017, I filed a copy of the foregoing utilizing the Commission's Electronic Filing System, which caused a copy to be served upon all parties of record via electronic mail.

<u>/s/ Shawn McMurray</u>
Shawn McMurray