Southwest Power Pool

FINANCE COMMITTEE MEETING

January 28, 2019

New Orleans, LA

• M I N U T E S •

Administrative Items

Chair Bruce Scherr called the meeting to order at 8:00 a.m. The following individuals participated in the meeting.

Bruce Scherr	SPP Director
Susan Certoma	SPP Director
Jerry Peace	Oklahoma Gas & Electric
Laura Kapustka (phone)	Lincoln Electric
Mike Wise	Golden Spread Electric Cooperative
Sandra Bennett (phone)	American Electric Power
Tom Dunn	SPP

Others attending included:

Denise Buffington	Evergy
Jim Jacoby	American Electric Power
Richard Ross	American Electric Power
Dennis Reed	Midwest Regulatory Consulting, LLC
Rob Janssen	Dogwood Energy, LLC
John Olson	Evergy
Darren Ives	Evergy
Patrick Cleary	FERC
Traci Bender (phone)	NPPD
Heather Starnes (phone)	MO Joint Municipal Electric Utility Comm
Stan Payne (phone)	Stephens
Jim Goss (phone)	Stephens
Kevin McBride (phone)	Stephens
Matt Jones (phone)	Stephens
Nick Brown	SPP
Carl Monroe	SPP
Lanny Nickell	SPP
Scott Smith	SPP

Minutes from the October 30, 2018 meeting were reviewed. Jerry Peace motioned to approve the minutes. The motion was seconded by Mike Wise and approved by unanimous voice vote.

Corporate Liability Insurance Stewardship Report

Representatives from Stephens Insurance, LLC provided an overview of the property & casualty, professional liability and director and officer insurance markets. In general, they expect renewal premiums across most lines to increase from 1%-3% with potential 8% increase expected in D&O lines.

Administrative Fee Recovery

John Olsen, chair of the SPP 1A Task Force, presented a new rate recovery structure being proposed by the 1A Task Force and provided examples of how the new structure would impact various types of customers. The 1A Task Force recommended a rate recovery structure using four rate schedules (1 based on transmission usage, 1 based on TCR usage, 2 based on energy market volumes). Mike Wise made a motion to accept the recommendation of the 1A Task Force. The motion was seconded by Laura Kapustka and approved by a voice vote of 5 in favor and 1 abstention. Jerry Peace, OG&E, abstained because the proposed structure, while an improvement over the current recovery structure, had room for improvement to better align the rates with the beneficiaries and users of the services.

2018 Financial Report

SPP staff reported on the unaudited financial results for the 2018 fiscal year. Key highlights include: i) projected over-recovery of $12.8 million, ii) net income of $15 million, iii) outstanding debt down $23 million since 2017, iv) deficit equity position of ($142 million). Staff also discussed issues SPP is experiencing in its project to replace its settlements system which moved to a "red" health indicator earlier in January.

Actuary Assumption Review

SPP staff discussed its recommendations for the four primary assumptions required for pension accounting and valuation: i) discount rate – staff recommended a discount rate of 5.00% in accordance with SPP's process for determining the discount rate assumption; ii) investment rate of return – staff recommends remaining at 7.00% long-term rate of return; iii) rate of compensation change – staff recommends remaining at 4.00% iv) staff recommended utilizing the current IRS mortality tables in accordance with Finance Committee directives from December 2015.

Jerry Peace made a motion to accept the assumptions presented by staff. The motion was seconded by Sandra Bennett and approved by unanimous voice vote.

Line of Credit Renewal

SPP staff presented a recommendation to extend the maturity of SPP's $30 million revolving line of credit facility from October 2019 to October 2021. All other terms and conditions of the facility would remain unchanged.

Mike Wise made a motion to approve the extension of the maturity date to October 2020. The motion was seconded by Susan Certoma and approved by unanimous voice vote.

Market Default in PJM

SPP staff presented some publicly available information regarding the Greenhat Energy, LLC default experienced in the PJM Interconnection market. The presentation highlighted some differences between the PJM and SPP markets which today indicate a lower probability of that magnitude of default occurring in the SPP market.

Financial Policy

The Committee engaged in an open discussion on several aspects of SPP's financial policy and expenditures.

Future Meetings

The next meeting of the Finance Committee is scheduled for Monday April 29, 2019 in Tulsa, OK beginning at 8:00 a.m. and ending at 11:30 a.m.

There being no further business, Bruce Scherr adjourned the meeting at 11:50 a.m..

Respectfully Submitted,

Thomas P. Dunn
Secretary

Southwest Power Pool, Inc.

FINANCE COMMITTEE MEETING

January 28, 2019

DoubleTree Downtown – New Orleans, LA

• A G E N D A •

8:00 a.m. – 11:30 a.m.

1. Administrative Items *(10 minutes)* .... Bruce Scherr
2. Corporate Liability Insurance *(30 minutes)*...
    a. Stewardship Review.. Stan Payne, Stephens Insurance
3. Administrative Fee Recovery *(30 minutes)* ****ACTION**** ....John Olson
4. 2018 Financial Review (*30 minutes*) .... Tom Dunn
5. Actuary Assumption Review *(20 minutes)* ****ACTION**** .... Tom Dunn
6. Line of Credit Renewal *(20 minutes)* ****ACTION****..Scott Smith
7. Market Default in PJM – Lessons Applicable to SPP *(20 minutes)*......................................Scott Smith
8. Financial Policy *(30 minutes)*.. Tom Dunn
9. Written Reports...
    a. December 2018 Financials
10. Future Meetings..

Southwest Power Pool

Southwest Power Pool

FINANCE COMMITTEE MEETING

October 30, 2018

Little Rock, AR

• M I N U T E S •

Administrative Items

Chair Bruce Scherr called the meeting to order at 2:00 p.m. The following individuals participated in the meeting.

Bruce Scherr	SPP Director
Larry Altenbaumer	SPP Director
Jerry Peace	Oklahoma Gas & Electric
Laura Kapustka	Lincoln Electric
Mike Wise	Golden Spread Electric Cooperative
Sandra Bennett	American Electric Power
Tom Dunn	SPP

Others attending included:

Denise Buffington	Evergy
Jim Jacoby	American Electric Power
Richard Ross	American Electric Power
Dennis Reed	Midwest Regulatory Consulting, LLC
Heather Starnes (phone)	MO Joint Municipal Electric Utility Comm
Cindy Ireland	Arkansas Public Service Commission
Jason Chaplin	Oklahoma Corporation Commission
Mark Crisson	SPP Director
Phyllis Bernard	SPP Director
Graham Edwards	SPP Director
Nick Brown	SPP
Carl Monroe	SPP
Barbara Sugg	SPP
Lanny Nickell	SPP
Sheri Dunn	SPP
Zeynep Vural	SPP
Dianne Branch	SPP
Carson Hampson	SPP
Chad Moore	BKD, LLC

Minutes from the September 25, 2018 meeting were reviewed. Jerry Peace motioned to approve the minutes. The motion was seconded by Mike Wise and approved by unanimous voice vote.

2018 Financial Audit

Chad Moore of BKD, LLC presented the 2018 financial audit plan identifying significant focus areas for the audit and seeking input from the Committee on other areas which the Committee would like audited.

The Committee dismissed SPP staff and convened a brief executive session with BKD, LLC.

SPP 2019 Budget and Administrative Fee

SPP staff presented highlights from the 2019 budget starting with a reconciliation of SPP's net revenue requirement from the 2018 budget through the 2018 forecast then to the 2019 budget. Next, staff presented a closer view into major budget categories including salary and benefit expenses, outside services expenses, capital expenditures, debt service requirements, and outstanding debt. Additionally, where available, staff provided comparisons of SPP results to the U.S. based ISO/RTO peers.

Following additional dialogue on individual aspects of the budget, Mike Wise made a motion to accept the budget as submitted. The motion was seconded by Sandra Bennett and approved by unanimous voice vote. Jerry Peace mad a motion to establish an assessment and schedule 1A rate of 39.4¢/MWh effective January 1, 2019. The motion was seconded by Laura Kapustka and approved by unanimous voice vote.

Administrative Committee Report

SPP staff presented highlights of the Administrative Committee's work during 2018, focusing primarily on the performance of the investment managers for the SPP Retirement Plan assets and the SPP 401(k) plan investment options. The Administrative Committee has been pleased with the performance of the managers.

Future Meetings

The next meeting of the Finance Committee is scheduled for Monday January 28, 2019 in New Orleans, LA beginning at 8:00 a.m. and ending at 11:30 a.m.

There being no further business, Bruce Scherr adjourned the meeting at 4:30 p.m..

Respectfully Submitted,

Thomas P. Dunn
Secretary

2018 STEWARDSHIP REPORT

November, 2018

SPP Southwest Power Pool

Stephens

Agenda

1. STEPHENS INSURANCE 2017 RESULTS 4
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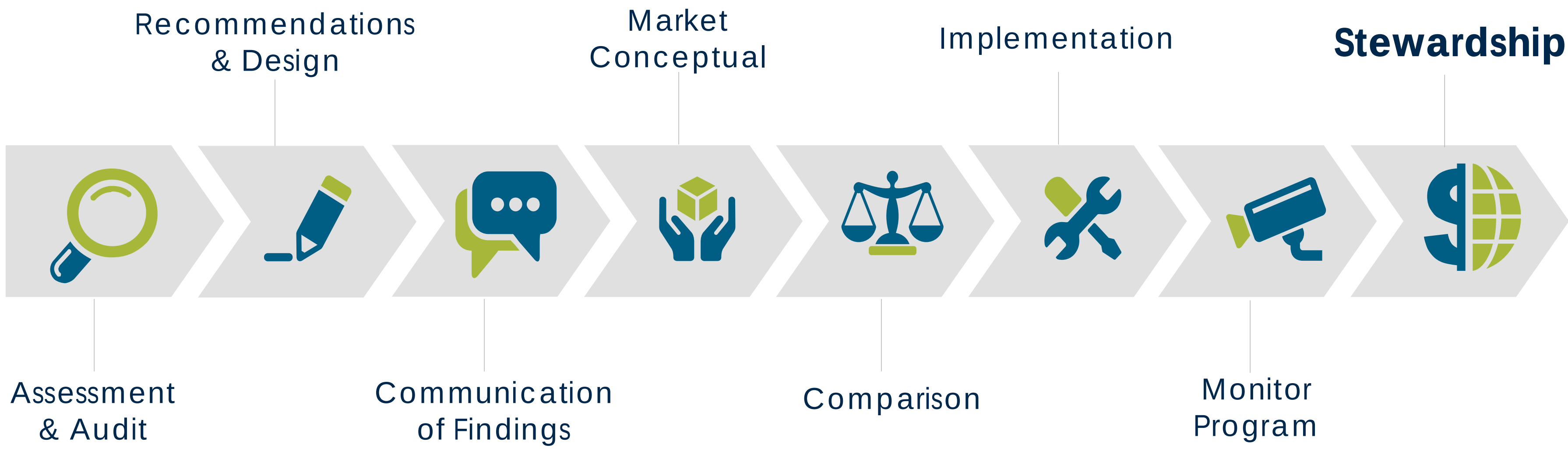
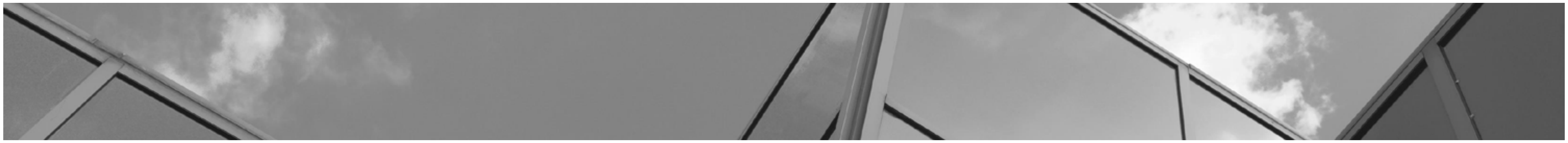
8. DISCUSSION ITEMS/RENEWAL PLANNING 52

Our Process


Recommendations & Design
Market Conceptual
Implementation
Stewardship
Assessment & Audit
Communication of Findings
Comparison
Monitor Program



1. STEPHENS INSURANCE 2017 RESULTS

Property & Casualty Division

Top 75

Stephens Broker Ranking
(If Disclosed)

95%

Rollover
All Property & Casualty

+18%

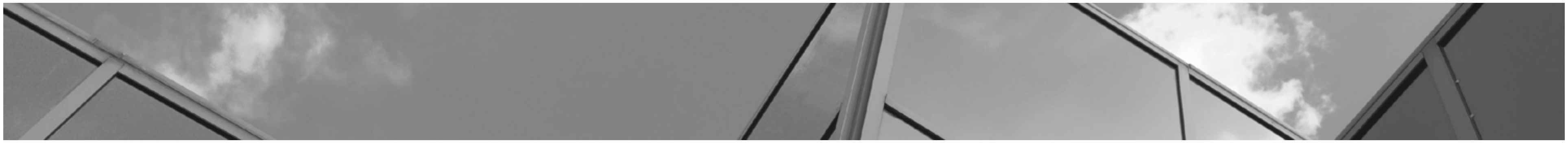
Organic Growth

104%

Retention
(Risk Management)

+14%

Revenue Growth
(All Insurance Entities)



2. STEPHENS CONTACTS

Account Team

EXECUTIVE MANAGEMENT TEAM
NICK BROWN - CEO

INTERNAL RISK MANAGEMENT FUNCTION
TOM DUNN
SCOTT SMITH

STAN PAYNE
EXECUTIVE VICE PRESIDENT, ACCOUNT EXECUTIVE

BROKERAGE SERVICES

- **MATT JONES** – AVP, ACCOUNT MANAGER
- **KEVIN MCBRIDE** – SVP, EXECUTIVE RISK
- **SAME ROBLES** – AVP, EXECUTIVE RISK
- **BOB WATKINS** – SVP, SYNDICATION
- **PRENTICE MCINTOSH** – VP, RISK MANAGEMENT

RISK MANAGEMENT

- **JIM GOSS** – SVP, RISK MANAGEMENT
- **PATRICK MCALPINE, JD** – SVP, GENERAL COUNSEL
- **JAMES FORTNER** – VP, ENERGY DIVISION
- **MIKE DRAGNA & BOB CARLETON** – ENERGY DIVISION
- **JOHN HARRIMAN** – HR COMPLIANCE

CLAIMS MANAGEMENT

- **DENVER FLETCHER** – SVP, CLAIMS MANAGEMENT
- **COURTNEY MCLARTY, JD** – VP, CLAIMS MANAGEMENT
- **HEBA BROWN** – CLAIMS MANAGEMENT
- **CASEY PROCOP** – CLAIMS COORDINATOR
- **JOEY BROWN** – PROP. CLAIMS SPECIALIST

LOSS CONTROL

- **DAVID NIGUS** – VP, LOSS CONTROL
- **PRESTON KELLER** – VP, LOSS CONTROL

Contact Information

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Insurance Leadership

Martin M. Rhodes

President and Chief Executive Officer

Mr. Rhodes is President and CEO of Stephens Insurance, LLC and President of Stephens Consulting, LLC. He began his insurance career in 1973 with Fireman's Fund Insurance Co.

Mr. Rhodes founded Rhodes & Associates, Inc. in 1986 and then sold it to Brown & Brown, a publicly traded broker, in 2002. He joined Stephens as President and CEO in January 2005.

Mr. Rhodes earned a Bachelor of Arts from Hendrix College in 1972. He is the past President of the Rotary Club of Little Rock for 2006-2007 and was also the past Chairman of the Board for the Boys & Girls Club of Central Arkansas. He is currently serving on the Board of Directors of Arvest Bank, Board of Trustees of Hendrix College and was 2012 Chairman of the Little Rock Regional Chamber of Commerce.

Stan Payne

Executive Vice President
Director of Property & Casualty

Mr. Payne joined Stephens Insurance in March 2009 in our Risk Management Division. In January 2012 he was named Executive Vice President and Director of Property & Casualty. Additionally, he continues to lead a team providing Risk Management and Insurance services to large public and private companies.

Prior to joining Stephens, Mr. Payne spent 12 years providing similar services at Regions Insurance. He began his insurance career at Sedgwick James in 1995. Experienced with Risk Management in various industries, Mr. Payne has designed complex property placements, large retention casualty programs, as well as a variety of alternative risk financing options. He has also worked with clients' mergers, acquisitions and divestitures to coordinate insurance placements and risk management services. Mr. Payne earned a BA from the University of Arkansas at Little Rock in 1995 and completed the Chubb/Wharton Executive Leadership Development Program at the Wharton School in 2003.

Account Management & Brokerage

Matt Jones

Assistant Vice President
Account Manager

Mr. Jones joined Stephens Insurance in 2009, providing customer service, claims coordination, and account management services to large public and private clients. Prior to joining Stephens Insurance, he spent one year providing similar services at Regions Insurance, formerly known as Rebsamen Insurance. In the four years prior, he provided similar services as an account manager and producer for an insurance firm in Tennessee; Mr. Jones has a wide array of insurance experience in hospitality, manufacturing, not-for-profit religious institutions. He has earned the accreditation of Certified Insurance Counselor (CIC) and is pursuing his accreditation of Certified Risk Manager (CRM).

Robert Watkins

Senior Vice President
Marketing

Mr. Watkins joined Stephens in 2010 as Senior Vice President joining a team of professionals providing Risk Management and Insurance services to large public and private companies. Prior to joining Stephens, Mr. Watkins spent 10 years as Executive Vice President and Principal at Risk Services of Arkansas, LLC, formerly First Arkansas Insurance. Prior to that he served for two years as Senior Vice President and Director of Risk Management at Sedgwick of Arkansas and 15 years as Senior Vice President of Rebsamen Insurance, both in Little Rock. He began his insurance career in 1974 with the Seibels Bruce Group in Columbia, South Carolina.

Experienced with Risk Management and Insurance Brokerage in heavy manufacturing, retail, transportation, construction, energy exploration and production as well as gas and electric utility industries. Mr. Watkins has experience with large property placements, a variety of loss sensitive and alternative risk finance casualty placements as well as management liability. His experience also includes working with client risk management issues associated with merger, acquisition and divestiture transactions.

Mr. Watkins earned a BA in Business Administration from the University of South Carolina in 1974. He also attained the professional designations of Chartered Property and Casualty Underwriter, CPCU; Associate in Risk Management, ARM and Chartered Life Underwriter, CLU.

Account Management & Brokerage

Prentice McIntosh

Vice President
Risk Management

Ms. McIntosh joined Stephens Insurance, as Vice President, to assist in forming their Energy Group. Prior to joining Stephens, she had 8 years of experience with Regions Insurance in property and casualty insurance working with clients in a variety of industries.

Through those years, she has developed a focus on Energy/Utility clients. She has experience with large Casualty and Nuclear placements, in addition she has experience placing complex property programs with multiple carriers/markets in the US, London, Europe and Bermuda. She has also worked with clients to manage their exposures through the use of a captive program. While managing these clients, she has assisted them in identifying and insuring Non-Regulatory risks.

Ms. McIntosh earned a BA of Marketing from the University of Arkansas in 2002 and has earned the designations of Accredited Advisor of Insurance and Associate in Risk Management.

Executive Risk & Cyber

Kevin McBride

Senior Vice President
Executive Risk

Mr. McBride is a Senior Vice President and Management Liability specialist in the Dallas office of Stephens Insurance, LLC. Since entering the insurance industry in 1987, he has held underwriting and management positions with stock insurance companies, owned a managing general agency under a binding authority with Lloyds of London and held senior positions with regional and national insurance brokers.

Mr. McBride serves as a resource across the entire Stephens organization for Directors & Officers Liability, Employment Practices Liability, Fiduciary Liability and related management liability products. He received a Bachelor of Science degree in economics from Texas A&M University and is a member of the Professional Liability Underwriting Society.

Sam Robles

Assistant Vice President
Executive Risk

Mr. Robles joined Stephens Insurance in 2015 as a specialist with the Executive Risk Department, working under the direction of Kevin McBride. Mr. Robles is responsible for the account management, analysis and marketing support for Directors & Officers Liability, Employment Practices Liability, Fiduciary Liability and related Executive Risk coverages for private and publicly traded companies for our office.

Mr. Robles has over 15 years of experience in the areas of professional liability and executive risk as an underwriter and a broker most recently with USI.

Risk Management

Jim Goss

Senior Vice President
Risk Management

Mr. Goss joined Stephens Insurance in 2009, providing Risk Management services to large public and private clients. Prior to joining Stephens, he spent six years providing similar services at Regions Insurance, formerly known as Rebsamen.

Prior to joining Rebsamen, Mr. Goss had 17-plus years of experience as a Risk Manager and head of related departments for two Fortune 500 companies (retail and telecommunications/information technology) as well as seven years of insurance carrier experience as a claim adjuster and supervisor.

Mr. Goss has had extensive experience with loss-sensitive programs including self-insurance, captives and retrospectively rated plans. He was EVP of a captive operation with a third-party business an also established a claims self-administration department as Risk Manager, including the development of a technical claims processing system. A graduate of the University of Central Arkansas, Mr. Goss is past President of the Arkansas Chapter of the Risk and Insurance Management Society.

Legal

Patrick McAlpine

Senior Vice President
Assistant Chief Operating Officer / Chief Legal Counsel

Mr. McAlpine is Senior Vice President and General Counsel for Stephens Insurance, LLC. He earned a Bachelor of Arts degree from the University of Arkansas summa cum laude in 1996 and a Juris Doctor degree with high honors from the University of Arkansas at Little Rock in 1999. Mr. McAlpine was Editor-in-Chief of the UALR Law Review in 1998-1999.

Mr. McAlpine is admitted to practice law in Arkansas and before the United States District Courts for the Eastern and Western Districts of Arkansas and the United States Court of Appeals for the Eighth Circuit. He was City Judge for the City of Cammack Village, Arkansas from 2004 to 2011. Mr. McAlpine is a member of the Arkansas Bar Association and the Pulaski County Bar Association.

Prior to joining Stephens Insurance, Mr. McAlpine was Assistant General Counsel for Staffmark Holdings, Inc. and was in private practice with the Little Rock firms of Quattlebaum, Grooms, Tull & Burrow PLLC and Williams & Anderson LLP.

Energy - Power

James Fortner

Vice President - Energy Group

James currently serves as Vice President of Stephens' Energy Division in our Little Rock office leading a highly productive team of risk management professionals focused on serving Investor Owned Utilities as an extension of their respective risk management staffs.

James joined Stephens Insurance in 2012 as Assistant Vice President and has been an integral contributor to Stephens' Energy Division. He is consistently engaged in the successful management of client's risk creating solutions with them for the identification, assessment, control and financing of their risks. These solutions include the transactional aspect of assisting them with complex property and casualty placements including named windstorm/surge zone property coverage, mechanical breakdown coverage for prototypical gas turbines, and nuclear generation as well as creative ways to manage these risks through self-insurance, captive vehicles, contractual risk transfer, builders risk programs, and other innovative means of managing or mitigating risk.

Prior to joining Stephens, he was engaged in serving an array industries in complex risk management at Regions Insurance and The Grace Group.

Fortner, a native of central Arkansas, earned his Bachelor of Business Administration in Insurance and Risk Management from the University of Central Arkansas in Conway.

Mike Dragna

Vice – President Energy Group

Mike brings over 35 years of Corporate Risk Management and Insurance experience to the Stephens Insurance-Energy Group. Mike joined Stephens Insurance in August 2018, after retiring from a 20-year career as Project Manager-Risk & Insurance with Entergy Corporation in New Orleans. During his time at Entergy, Mike was responsible for the administration of the corporate liability programs, construction risks, contract reviews and the negotiation of large complex property claims.

Mike's career spans 35 + years of Corporate Risk Management with 3 Fortune 500 corporations with emphasis in oil and gas, utility, offshore marine construction and mining, and includes foreign assignments in Singapore and Indonesia.

Mr. Dragna is a native of South Louisiana, and earned a BA from Southeastern La University, Hammond, LA and has completed the Entergy Executive Studies Program, Robert H Smith, University of Maryland. Mike has completed numerous insurance and risk management continuing education studies. Mike is a past president of the South Louisiana chapter of RIMS, and selected numerous times to participate as a Risk Manager in Residence at selected Universities, through the RIMS/Spencer Educational Foundation.

Energy - Power

Bob Carleton

Vice – President Energy Group

In 1992, following six years in the U.S. Navy nuclear program including time as a nuclear prototype instructor and submarine nuclear power system operator and mechanic, Bob began employment as a power plant operator and mechanic at City Utilities of Springfield, Missouri (CU). CU is a municipal utility with electric generation, electric transmission and distribution, gas transmission and distribution, public transit and telecommunication assets. He participated in two steam turbine generator overhauls and a gas turbine generator overhaul. In 2001, Bob transferred to the Electric Transmission and Distribution as a Power Quality Technician. He diagnosed and fixed commercial and residential customer electric issues as well as designed and constructed large commercial electric metering installations. He was an active member of the Safety Committee and also became the lead infrared survey technician for the utility and supervisor over the Power Quality Department.

In 2010 Bob accepted the position of Risk Manager for CU. While there he obtained the Associate of Risk Management and Associate of Enterprise Risk Management designations from AICPCU. His experience in the Navy and throughout the utility facilitated a strong risk management and loss control presence for the utility, enabling close working relationships with the utility asset managers. These relationships allowed Bob to implement insurer engineering recommendations and improve insurance coverage for the utility.

NRG Energy, Inc., a Fortune 200 Independent Power Producer, sought out Bob and offered him a position as Manager, Risk Insurance in 2015 where he worked for three years concentrating on their renewable energy assets across the U.S. He managed several large claims and financings for an extremely intense asset development and acquisition program during his time with NRG.

Bob joined Stephens Insurance in early 2018 to work with their Energy Team. His utility operations and risk management experience are a valuable asset to the team and their clients.

Claims Management & Advocacy

Denver Fletcher

Senior Vice President
Claims Management

Mr. Fletcher joined Stephens Insurance in 2009 as Senior Vice President assisting the Risk Management team by providing claims management and claim advocacy services. His insurance experience spans more than 31 years. Additionally, Mr. Fletcher leads Center Street Risk Services, Stephens in - house Third Party Administrator.

Prior to joining Stephens, he spent 14 years providing similar services at Regions Insurance formerly known as Rebsamen Insurance. He also managed Regions' claims division, which grew to administer claims in a 10-state region. He is a past president of the Arkansas Adjusters Association.

Mr. Fletcher has extensive experience in the presentation, adjustment, and advocacy of complex catastrophic property claims to the global marketplace. Additionally, he has worked on behalf of clients to use manuscript wording from property placements to achieve a positive response from underwriters. On rare occasions, Mr. Fletcher has been called to be a witness regarding the policy in place at the time of loss and very often with favorable outcomes for our clients. Mr. Fletcher's reputation with underwriters and carrier claims professionals spans the U.S., London, European, and Bermuda markets.

Courtney McLarty, J.D.

Vice President
Claims Management

Ms. McLarty joined Stephens Insurance, LLC as Vice President in the Claims Management Department in 2015. She earned a Bachelor of Arts degree in Classical Greek from the University of Georgia in 1994 and a Juris Doctor degree from the University of Arkansas at Fayetteville in 1997. Prior to joining Stephens Insurance, Ms. McLarty was engaged in private practice with the Little Rock firm of Wright, Lindsey and Jennings LLP with a focus on insurance defense, trucking and transportation defense, and insurance coverage dispute litigation.

Ms. McLarty is active in the community through organizations such as the Junior League of Little Rock (President 2009-2010), the 20th Century Club of Little Rock, and currently serves on the Board of the Pulaski County Bar Foundation. She graduated as a Fellow of the American Board of Trial Advocates Trial College held at Harvard Law School in 2014 and has been a member of the William R. Overton Inn of Court since 1999.

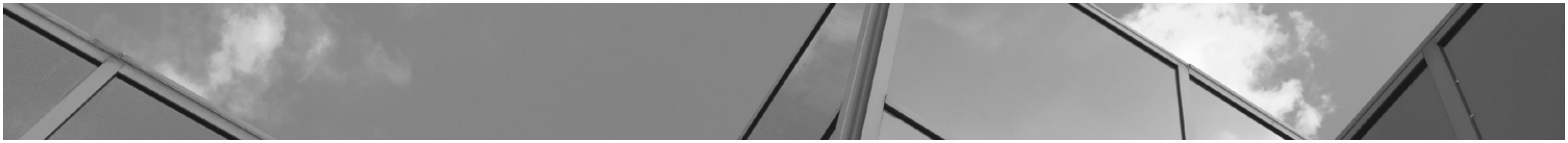
Claims Management

Heba Brown

P&C Claims Coordinator

Mrs. Brown joined Stephens Insurance, LLC in July of 2012 as a Claims Coordinator in our Claims Management Department. Since joining Stephens Insurance, Mrs. Brown has obtained her Arkansas Property and Casualty Producers and Arkansas Multi-Line Adjuster licenses.

Mrs. Brown holds a bachelor's degree in International Business from the University of Arkansas at Fayetteville. Prior to joining Stephens Insurance, Mrs. Brown worked in both transportation/logistics and banking.



3. STATE OF INSURANCE MARKET

P&C Insurer's Market Update: 2018 Q2

OVERVIEW (1/2)

- As reported by the Insurance Information Institute, the U.S. Property/Casualty insurance industry recorded a $6.0 billion underwriting profit for the first half of 2018. This compares to an underwriting loss $4.6 billion for the first half of 2017. It is too soon to determine how the third quarter storms will affect full year results, but in any event, the first six months profit will mitigate at least some of the potential loss from those events.

- CAT losses for the first half of 2018 fell by 23.2%, to $14.6 billion down from $18.0 billion for the first half of 2017.

- Alternatively, Non-CAT loses rose by 5.8% increasing to $186.7 billion compared to $176.4 billion for the first half of 2017. However, as a result of the lower CAT losses, total losses and LAE rose by only 3.6% from $194.3 billion to $201.3 billion.

- In spite of the modest increase in total loses, the trend for both commercial and personal auto losses continues to be increased frequency and severity driven by several factors including more drivers on the road, particularly at rush hour (10 million more people employed in the last four years), bad weather and distracted driving.

- Net written premium, which is direct written premium net of reinsurance, grew by 13.3% to $314 billion from the more typical growth on 4.1% for the first half of 2017. Changes in the tax law had a significant impact on reinsurance transactions for 2018 resulting in unusually high net written premium. Net written premium tends to grow based upon exposure growth and rate activity. Exposure growth is driven primarily by economic activity which has been unusually strong.

P&C Insurer's Market Update: 2018 Q2

OVERVIEW (2/2)

- Bolstered by the decrease in CAT losses relatively modest increase in Non-Cat losses, the industry was very profitable producing the second highest profit in the past 12 years. Helped by an increase in net investment income and realized capital gains, the industry profit more than doubled from $16.0 billion for first half of 2017 to $34.0 billion.

- Insurers' combined ratio improved to 96.2 for the first half of 2018 from 100.7 for the first half of 2017.

- Market capacity continues to be abundant as the overall industry capacity as measured by policyholders surplus reached another all-time high of $761.1 billion driven significantly by a strong stock market and increases in net written premium coupled with only modest increases in incurred losses and ALE. Policyholder surplus is the equivalent of net worth in other industries. As reported by reinsurance brokers, capacity from Insurance Linked Securities has continued to grow and is estimated to be near $100 billion up from $75 billion at the end of 2016. This growth in the ILS sector has continued to change the dynamics of the reinsurance market.

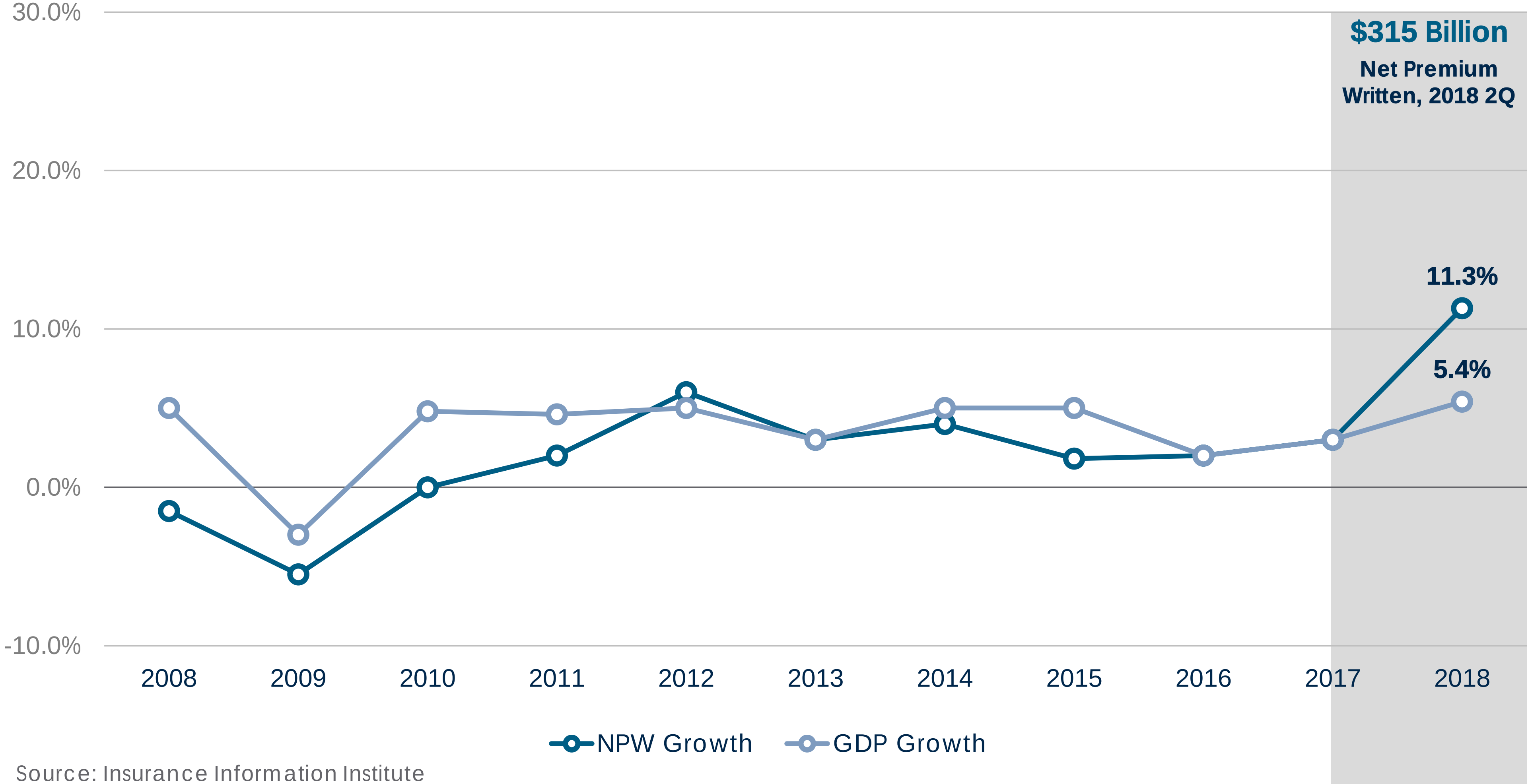
- As reported in the second quarter 2018 survey report from CIAB, rate changes ranged from -2.9% for workers compensation to +8.2% for commercial auto. In between, commercial property was up 2.2% while general liability and umbrella were up .8% and 1.5% respectively. Overall by line of business, average premiums for five major lines increased by 2.0%. By account size, average premiums increased by 1.5%. However, the disparity of change ranged from -13.6% to +28.5%. The wide disparity in rate action tends to reflect significant individual account underwriting by both line of business and individual account loss experience.

P&C Insurer's Market Update: 2018 Q2

Tax reform led to a spike in net written premium in 2018.

Annual Change in Net Premium Written & GDP

Percent Change

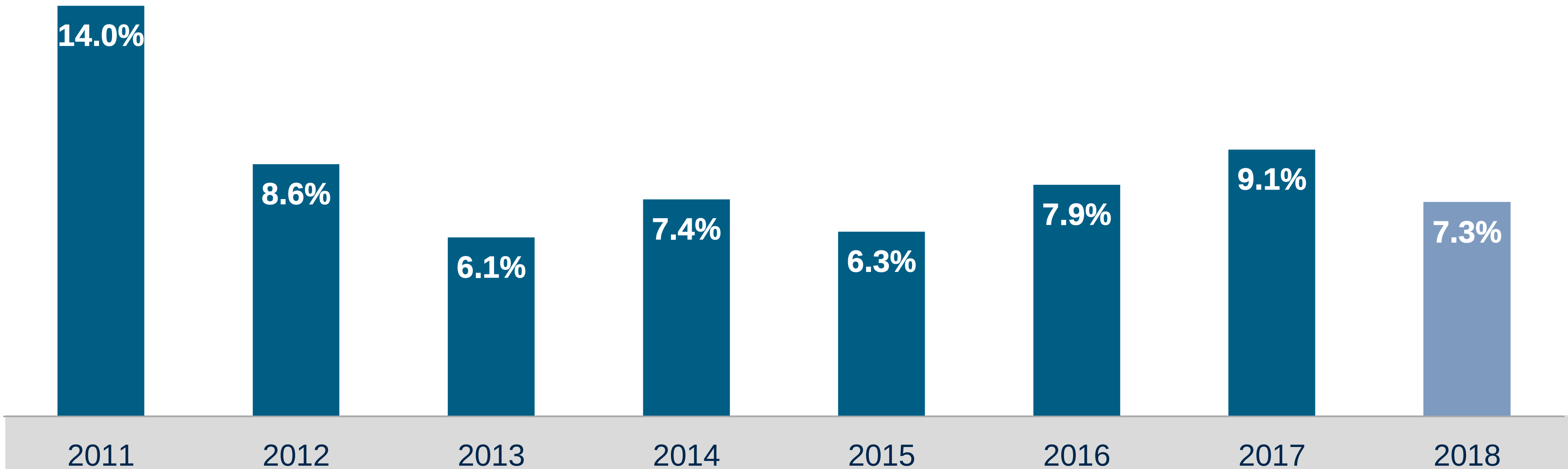


Source: Insurance Information Institute

P&C Insurer’s Market Update: 2018 Q2

Heavy winter storms and tornadoes affect catastrophic claims in the first half of the year.

Catastrophic Claims as a Percent of Total Claims
First Half of the Year, 2011 to 2018



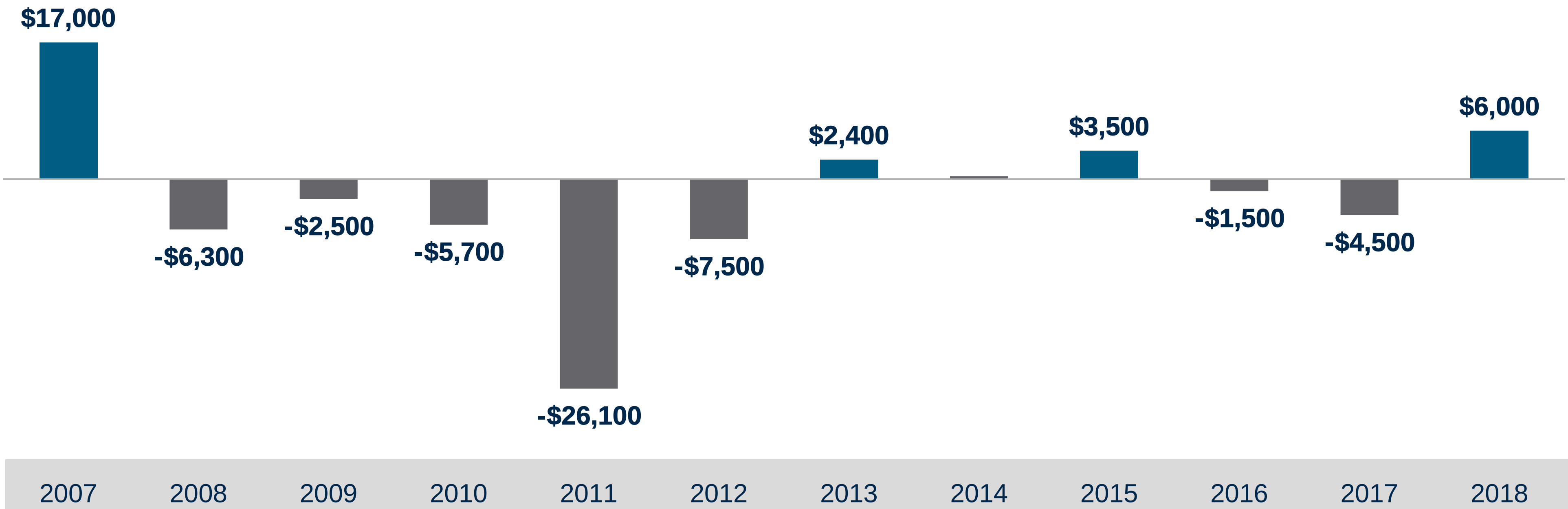
Catastrophic claims in the first half of 2018 were below the historic (2011-2018) average of 8.3%.

Source: ISO PCS; Insurance Information Institute calculations.

P&C Insurer's Market Update: 2018 Q2

Net underwriting gain improvement spurred by lower CAT activity in first half of 2018.

Net Underwriting Gains & Losses
First Half of the Year, 2007 to 2018



Underwriting results in the first half of 2018 recorded the highest gain in over a decade.

Source: ISO/PCI; Insurance Information Institute

P&C Insurer's Market Update: 2018 Q2

Property

- CAT wind/hail exposed properties are seeing double digit rate increases and those with adverse loss experience or that have lost capacity from incumbents can expect higher range double digit increases. Property accounts with no CAT exposure have been flat to small rate decreases. A recent CIAB survey reports commercial property rates overall up in the second quarter of 2018 by 2.2% with a disparity of from -15.0% to +45.4%. The 2017 storm season brought to an end the below average losses the U.S. has experience from Named Windstorms for the past several years and reminds us of the extremely volatile nature of those events and how quickly they can overshadow overall industry experience.

- Capacity for California earthquake continues to grow and is now at an all time high with capacity available for individual accounts form $750 million to $1 billion. Rates on large accounts with newer construction are generally flat to -5%. However, there are exceptions to the general trend such as in the south San Francisco Bay area. The new versions of the earthquake loss modeling released by RMS and AIR in 2017 have doubled the probable maximum loss (PML) in that area. The new releases indicated a need for 10% to 15% rate increase for property in the Bay area due to the potential for larger and more correlated events. However, due to abundant capacity still competing for that business, the rate increases have been mitigated.

- High hazard flood resisted the competitive market trend seen in other lines in recent years. Floods can and do happen anywhere and in any season which makes them much less predictable and therefore not easily modeled and priced. The recent devastation in Houston is clear evidence of widespread catastrophic damage posed by flood and will likely result in more firming in this market. Underwriters who are willing to write flood typically buy more reinsurance and will likely be impacted by expected changes in the reinsurance market.

P&C Insurer's Market Update: 2018 Q2

Primary & Excess Casualty

- Abundant capacity continues while reinsurance pricing has firmed somewhat for primary general liability, umbrella and excess liability. Underwriters are less aggressive on new and renewal business. Average increases of .6% for general liability and 1.5% for umbrella were recently reported for the second quarter of 2018 in the CIAB survey.

- As experience has continued to improve due to prior year rate increases and some moderation in medical inflation trends, underwriters continue to be competitive on workers' compensation in most jurisdictions. More underwriters are competing for workers compensation on a monoline basis. California, New York, Massachusetts, Florida, Pennsylvania and Illinois continue to be the most challenging jurisdictions with generally unfavorable results.

- According to recent CIAB surveys, increased capacity has driven workers compensation rates down by 2.9% in the second quarter of 2018.

- At the same time auto rates increased by 7.7% and 8.2% for the respectively for the first and second quarters of 2018. This reflects the continuing trend for the past several quarters of firming in the auto market. The second quarter of 2018 was the 28th consecutive quarter of increased commercial auto rates. Increased frequency and severity of losses are the driving factors in these increases.

- Umbrella and Excess Casualty tend to follow the pricing established in the primary commercial general liability and auto. Accounts with heavy auto exposure will likely see increases in the umbrella and excess liability similar to the increases in the primary auto liability. If primary casualty is relatively flat umbrella and excess liability will likely follow as there is still abundant capacity for these lines particularly if no heavy auto exposure.

P&C Insurer's Market Update: 2018 Q2

Cyber

- The insurance market remains competitive with dozens of insurers offering Cyber Liability
- At the same time, insurance company executives are on record as being concerned about the potential catastrophic loss their companies are subject to for a systemic Cyber loss, both within their Cyber books, but also other non-Cyber lines of business
- Significant liability payments under Cyber Liability policies are still mostly non-existent
- Cyber related Business Interruption losses are on the rise and the trend is expected to continue (i.e. Wannacry)
- The policy forms remain complex and without uniformity between insurers
- Policy forms cannot keep up with the ever changing threats
- Companies that handle credit cards and/or large amounts of personal information remain the primary target for hackers
- The best solution is to match the broadest coverage available with a robust risk management program and a state of the art technology platform

P&C Market Update: 2018 Q2

Cyber strikes are an increasing occurrence that affect millions of people.

Equifax – Credit Reporting Company – 143M consumers affected

Sonic/Chipotle/Arby's – All payment card systems compromised

Verizon – Breach of customer service records

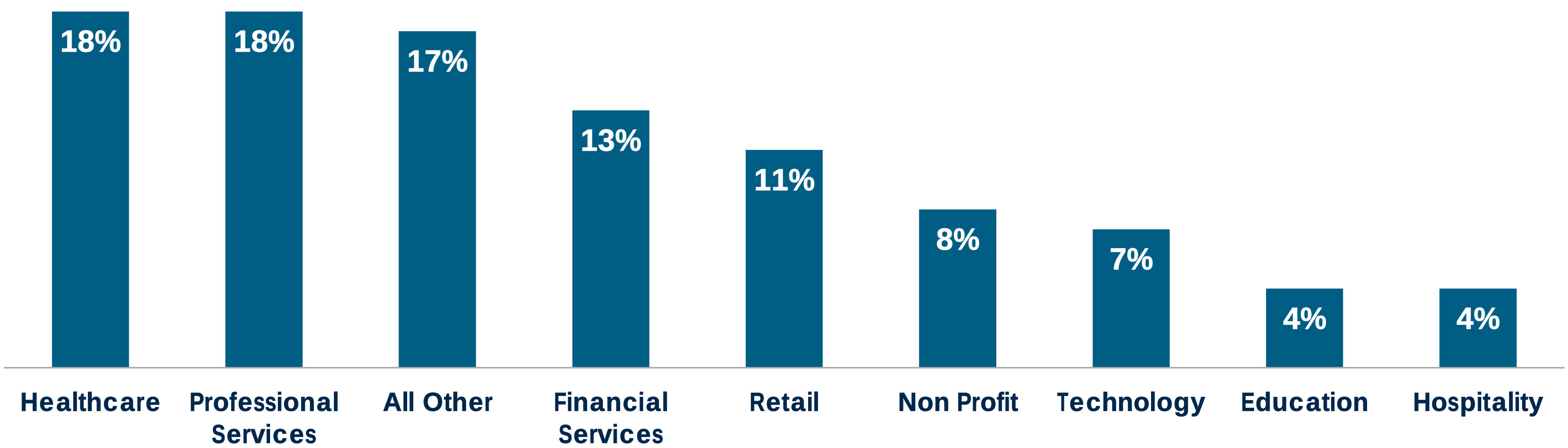
Gmail (Google) – 1M users affected

Uber – personal information of 57M users and drivers compromised – company paid $100k ransom

Brooks Brothers/Forever 21 – Payment card systems compromised

Healthcare and professional services were hit the hardest by cyber attacks.

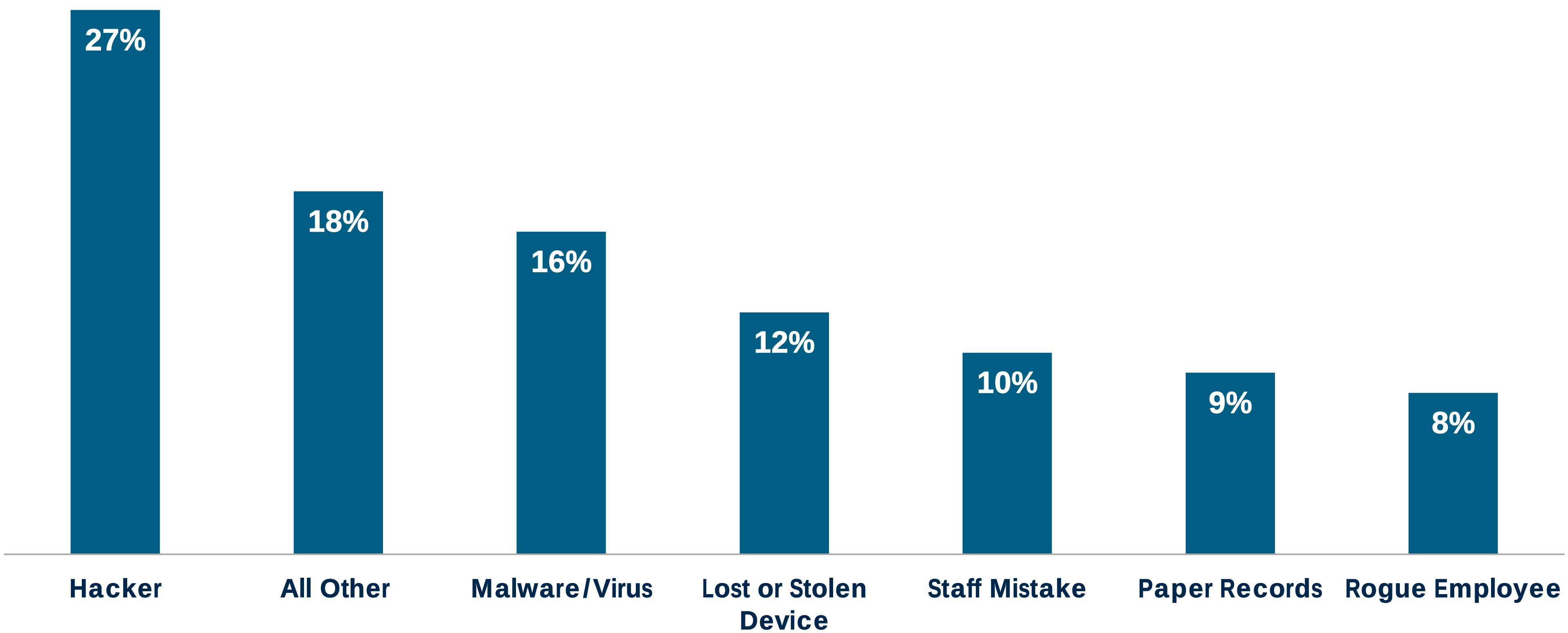
Cyber Claims by Business Sector
Percent of Claims



Source: NetDiligence Cyber Claims Study

Attacks by hackers are the most significant cyber risk.

Cyber Claims by Cause of Loss
Percent of Claims



Source: NetDiligence Cyber Claims Study

P&C Market Update: 2018 Q2

The cost of data breaches likely explains the significant investment in cyber security.

$86.4 Billion Total Company Expenditures on Cyber Security [3]	**$7.35** Million Total Average Costs of Data Breach [1]	**$1.56** Million Average Breach Response Cost per Organization [1]
$141 Dollars Average Cost of a Data Breach per Record [1]	**$697** Thousand Average Regulatory Defense Costs [2]	**$690** Thousand Average Notification Costs per Organization
$255 Thousand Average Legal Settlement [2]	**$121** Thousand Average Legal Defense Costs [2]	**$45** Thousand Average Regulatory Fine [2]

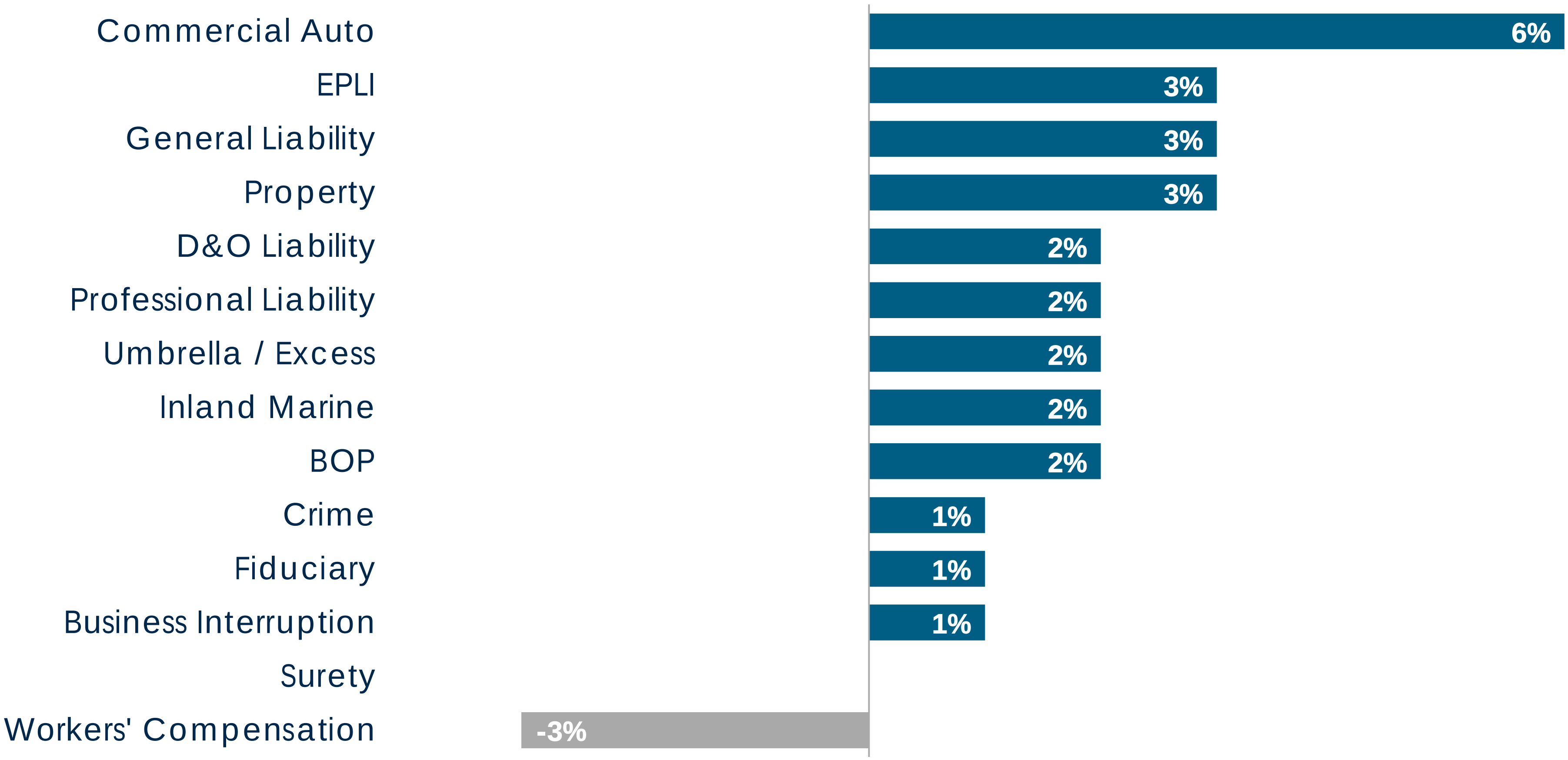
Source: [1] Ponemon 2017 Cost of Data Breach Study; [2] Net Diligence Cyber Claims Study; [3] Gartner Consulting.

Insurance Market Update: 2018 Q2

Premiums increased across all coverage classes, except for workers' compensation.

Premium Trends by Coverage Class

Percent Increase or Decrease from Year Prior

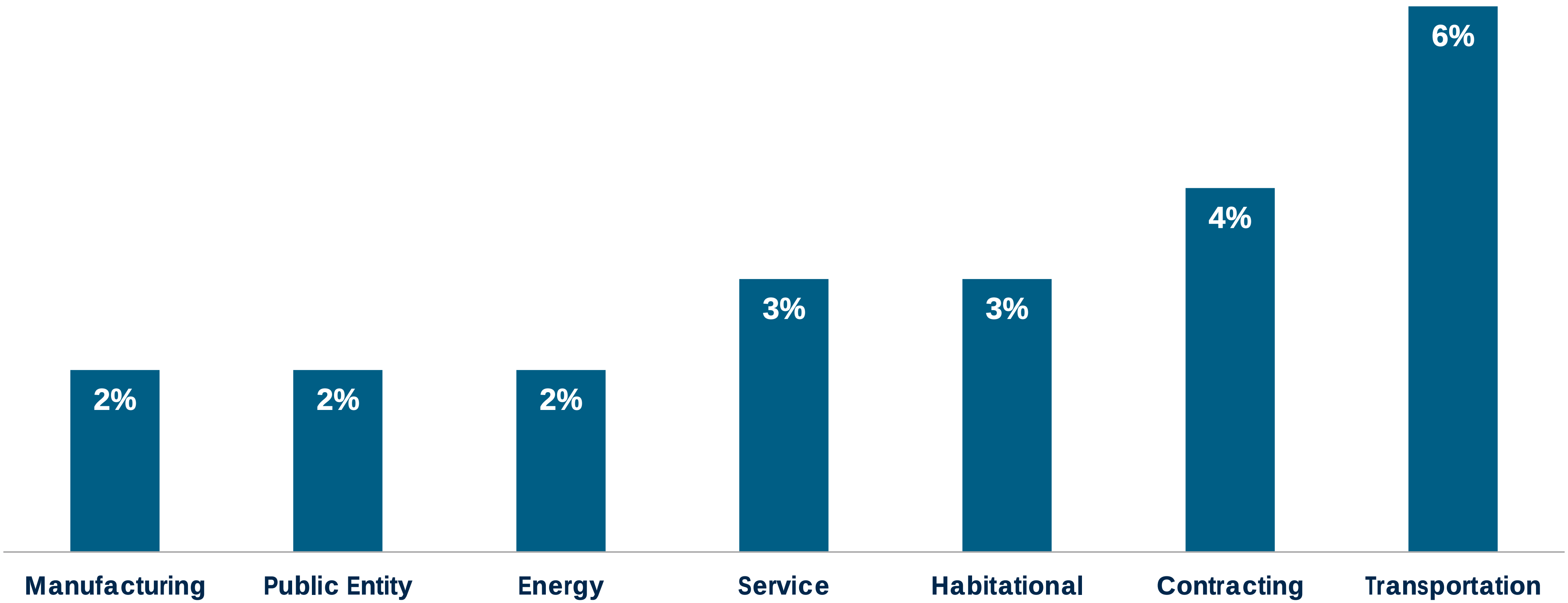


Source: Market Scout

Insurance Market Update: 2018 Q2

Across industries, the largest premium increases were in transportation and contracting.

Premium Trends by Industry Class
Percent Increase or Decrease from Year Prior

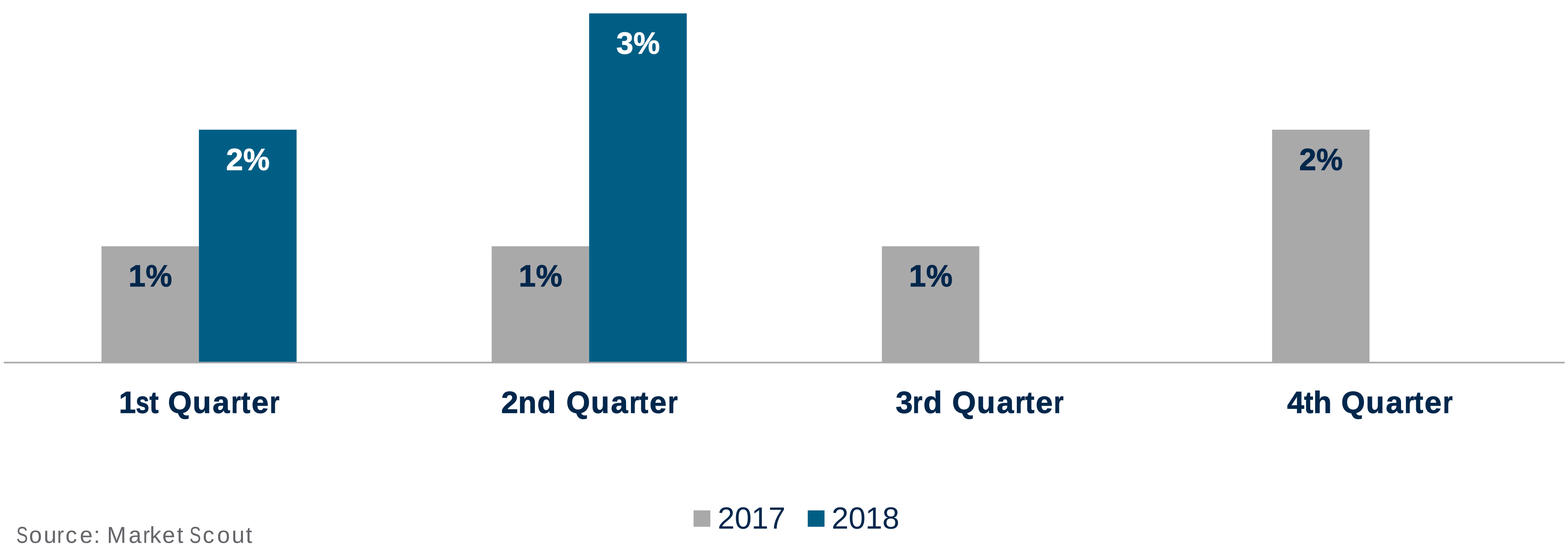


Source: Market Scout

Insurance Market Update: 2018 Q2

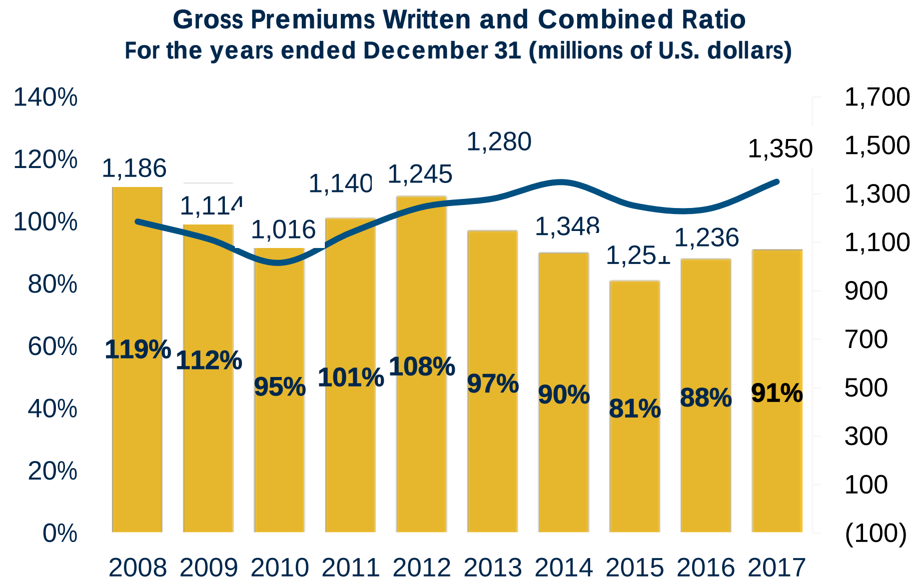
Overall, in the first half of 2018, quarterly rates were up relative to 2017.

Average Quarterly Rate Change (Year/Year)
2017 vs. 2018



Source: Market Scout

Aegis 2017 Financials



History of Liability Insurance for Utilities

Important Role of Industry Insurers: AEGIS and EIM

- Liability insurance for utilities in the past 60+ years fluctuated wildly as insurers entered the utility arena with great promise, only to depart abruptly a few short years later, leaving utilities scurrying for insurance and third party liability protections. Resulting uncertainty of available insurance and related cost led utilities to form their own dedicated insurers.

- Some major insurers such as Lloyds of London, General Reinsurance, The Home Insurance company, Lloyds again and countless minor players taking very small portions of large accounts at times when premiums were at peak during "tight" markets abandoned utilities when claims caught up with premiums and/or the competition was attracted to the peak-level premiums and ultimately forced the prices down. Many of those insurers later filed for bankruptcy leaving policyholders high and dry without the protection for which they had contracted.

- This behavior was evident in the decades from the 1950's through around 1986. A significant number of the utility insurers that were active in those years no longer exist. Meanwhile, the dedication and commitment of AEGIS (and EIM) for over thirty years to the energy industry is an insurance record. These utility-owned companies starkly differ from the multiple piece-players in the 1970's and 1980's.

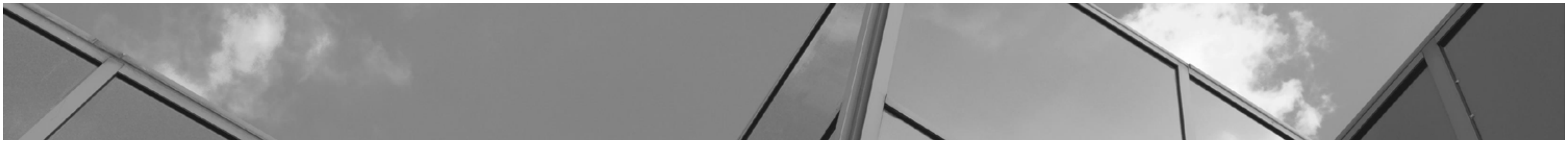
- Today, AEGIS is definitely the insurer of choice for over 314 Members consisting of gas and electric utilities in the U.S. and Canada with some similar entities in Europe joining in recent years.

- Recognizing a need for higher limits than AEGIS can provide ($35 million for Liability, Directors and Officers, for example), utilities formed Energy Insurance Mutual (EIM) to provide more limits (up to $100 million for Liability and $50 million D&O in addition to the AEGIS limits).

- Both of these companies are recognized and admired in the global insurance marketplace as the leaders for utility insurance. Other insurers in Europe and Bermuda (the major insurance centers for the world) are now very keen to follow these industry leaders and to offer additional limits over those provided by YOUR industry's mutuals.

AEGIS

EIM



4. ACTIVITIES & ACCOMPLISHMENTS

Activities & Accomplishments

- Stephens appreciates the opportunity to continue to serve Southwest Power Pool in the role of insurance and risk management advisor.

- **Overall**

- Property renewal rate maintained at .04 per $100 of insured values.

- Assisted in completion of Cyber coverage assessment

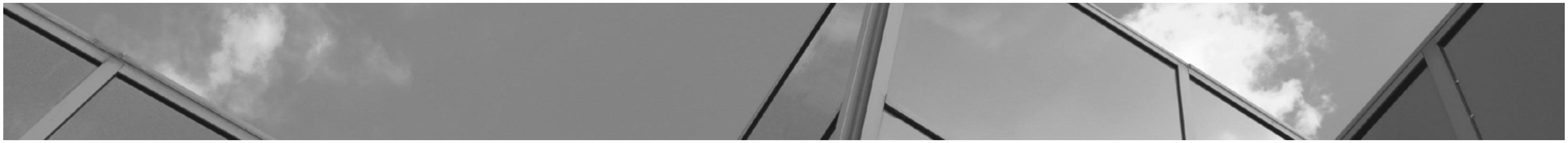
- Cyber liability review and marketing efforts with both Aegis and various other insurers. Cyber coverage placed with AIG and Lloyds for a total of $20M in coverage.

- Travel to New Jersey for Aegis underwriter meeting. Jim Goss from Stephens and SPP leadership in attendance.

- **Risk Management**

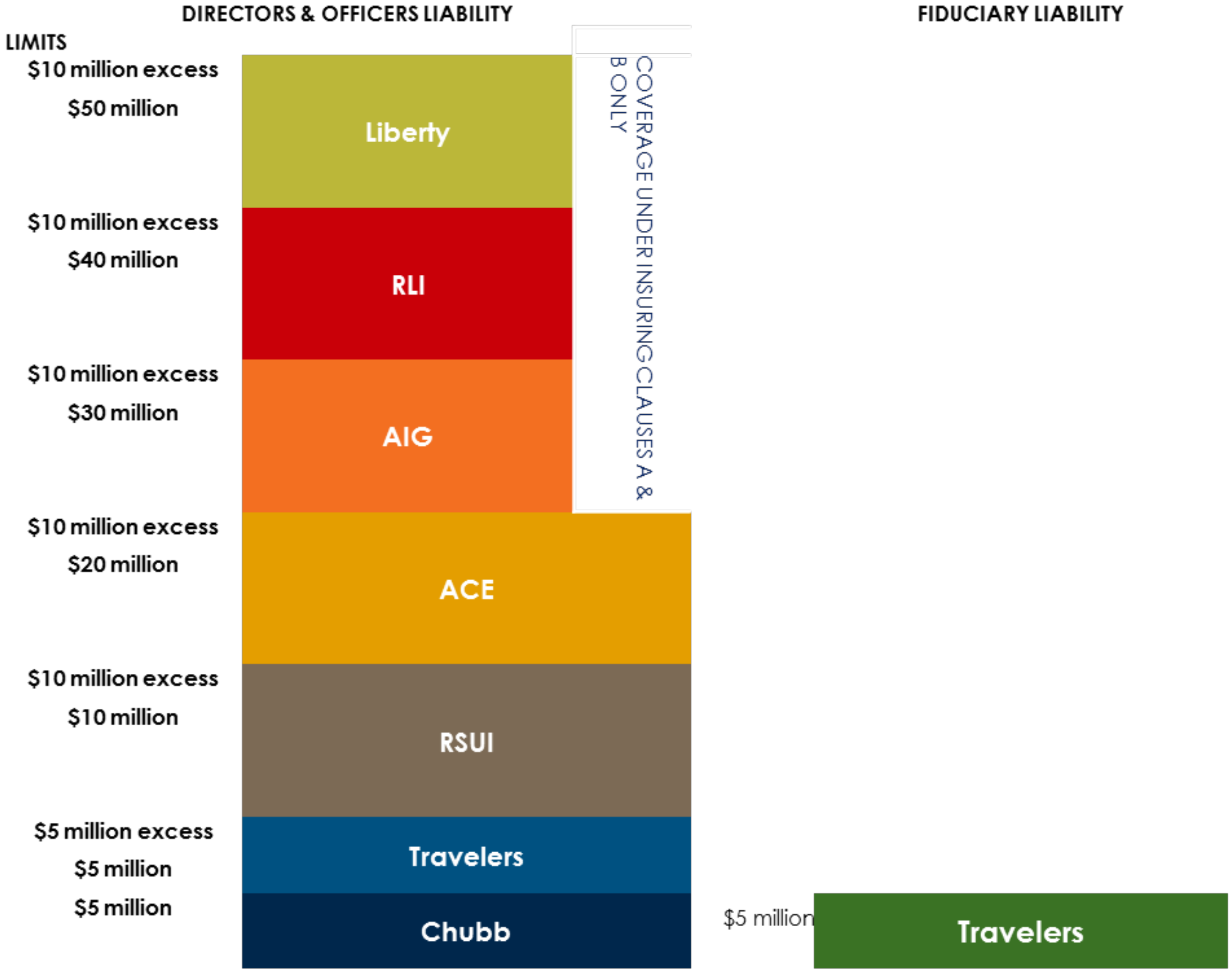
- Review of FEMA flood map revision of Rock Creek area and impact on SPP property.

- Everest loss control visit with favorable results and no recommendations pending from visit.



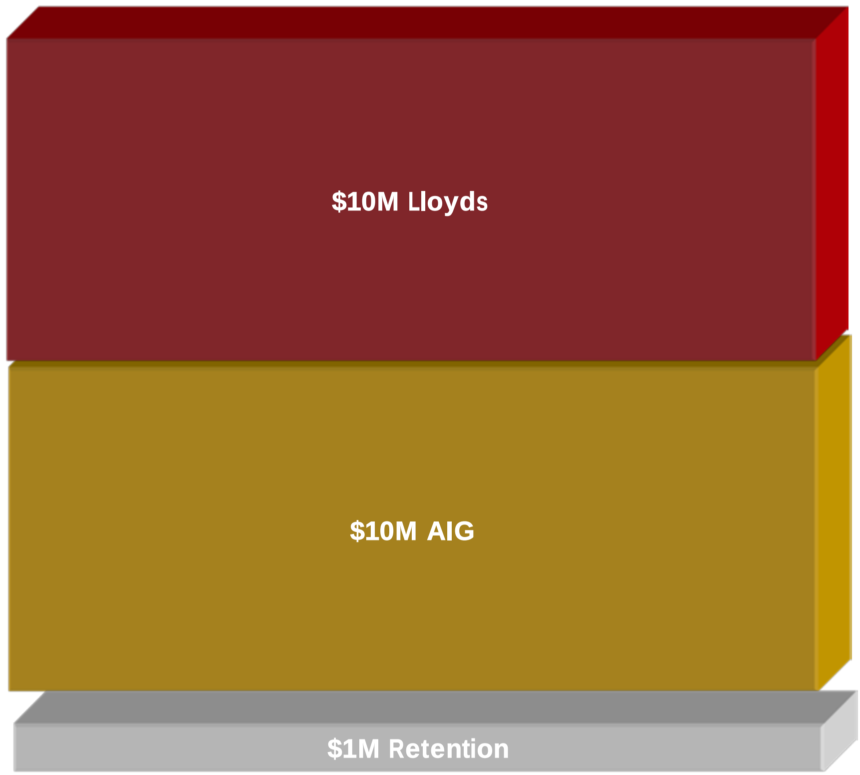
5. INSURANCE PROGRAM OVERVIEW

Executive Liability & Financial Products

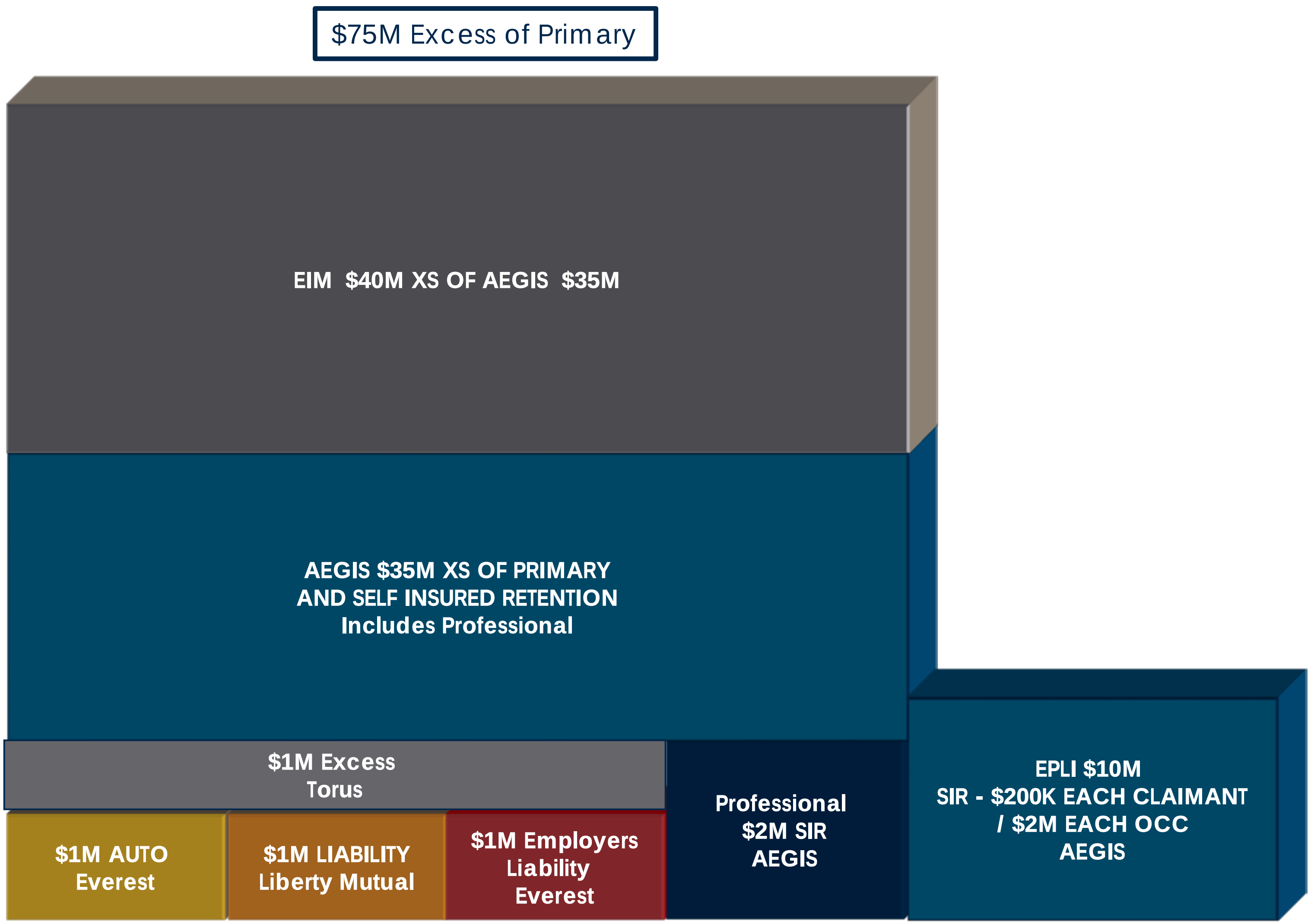


RETENTIONS			
D&O	$0 Non-indemnified/$15k indemnified & entity	Fiduciary	$2,500

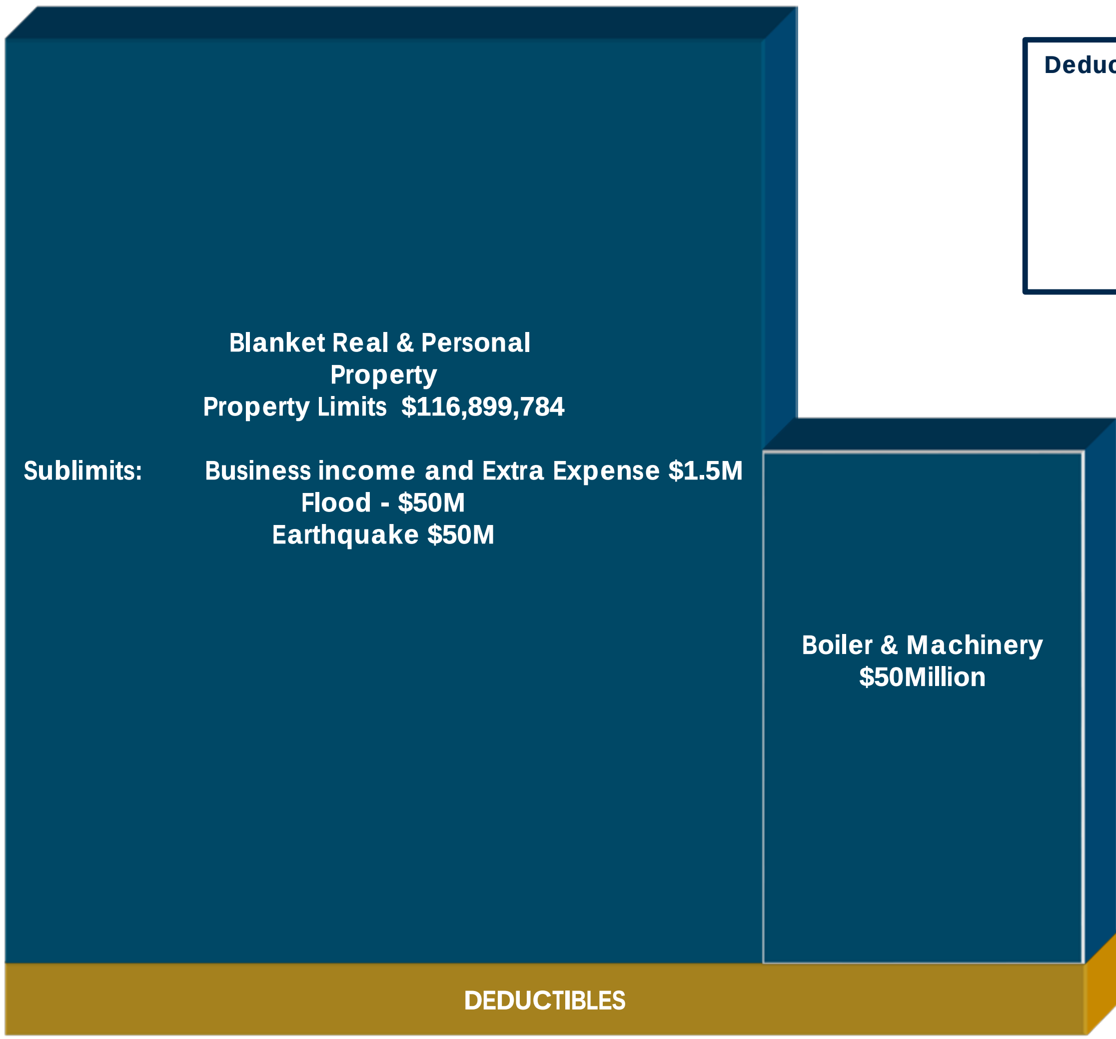
Cyber Liability Limits



Liability Limits



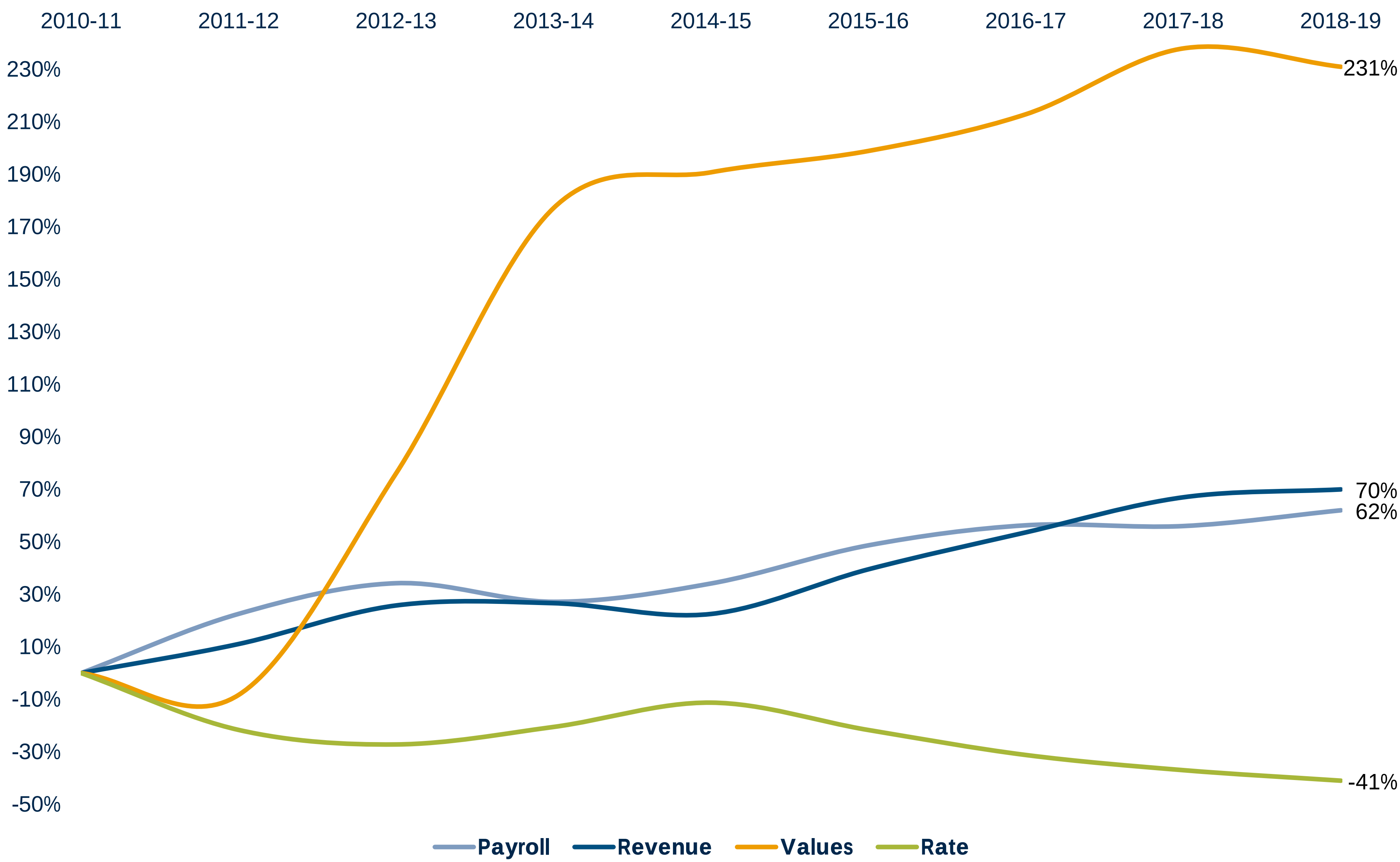
Property Limits

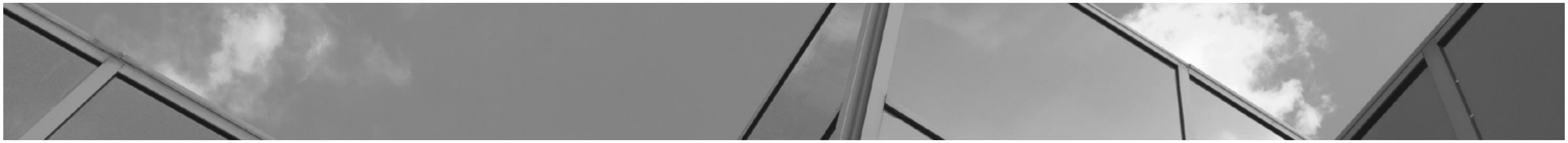


Deductibles:

All Perils	$250,000
Flood	$250,000
Quake	$250,000
Named Storm	$250,000
Other Wind/Hail	$250,000
Time Element	$250,000
Machinery	$10,000

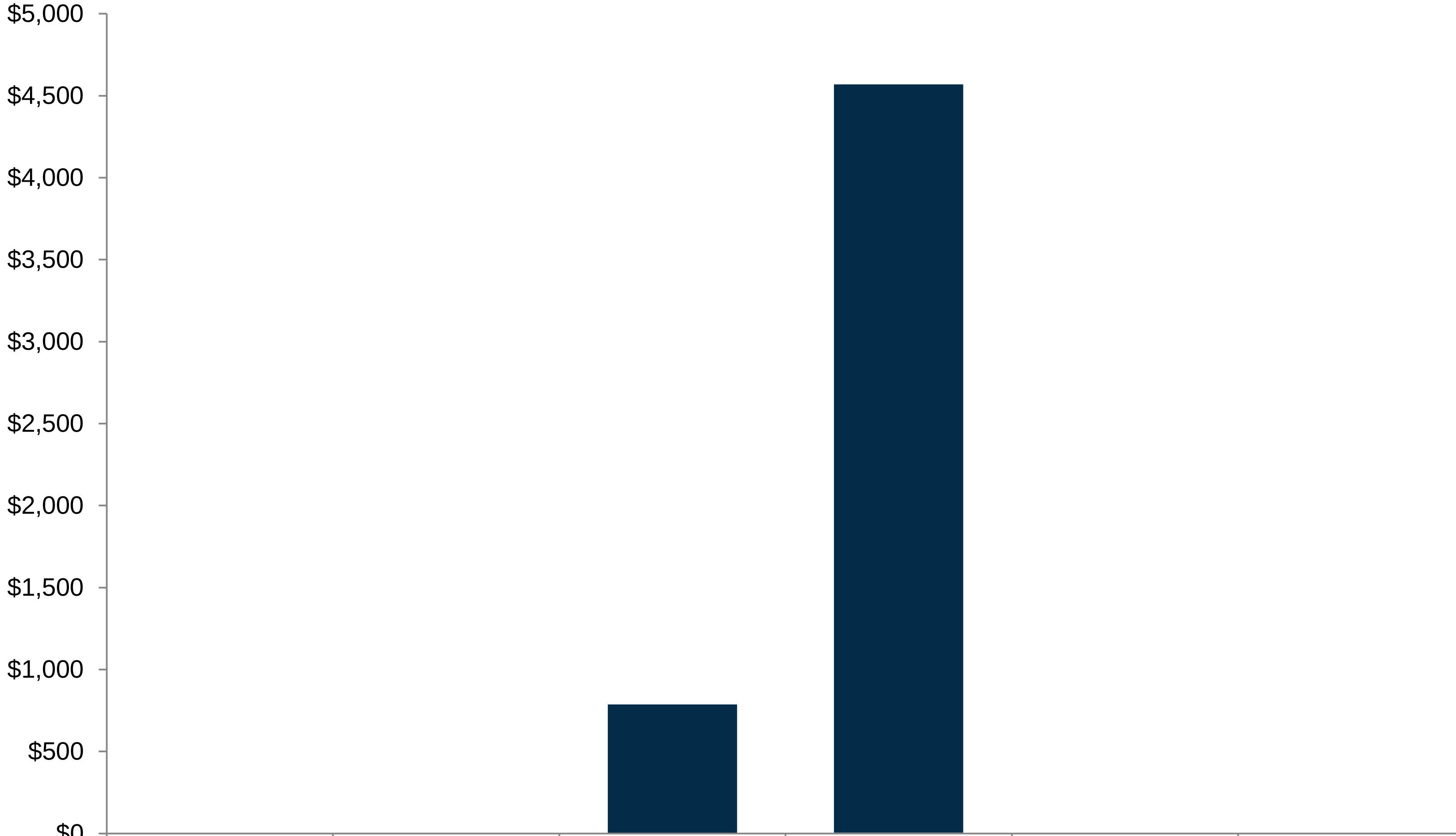
Premium Base Rate Versus Rate Change





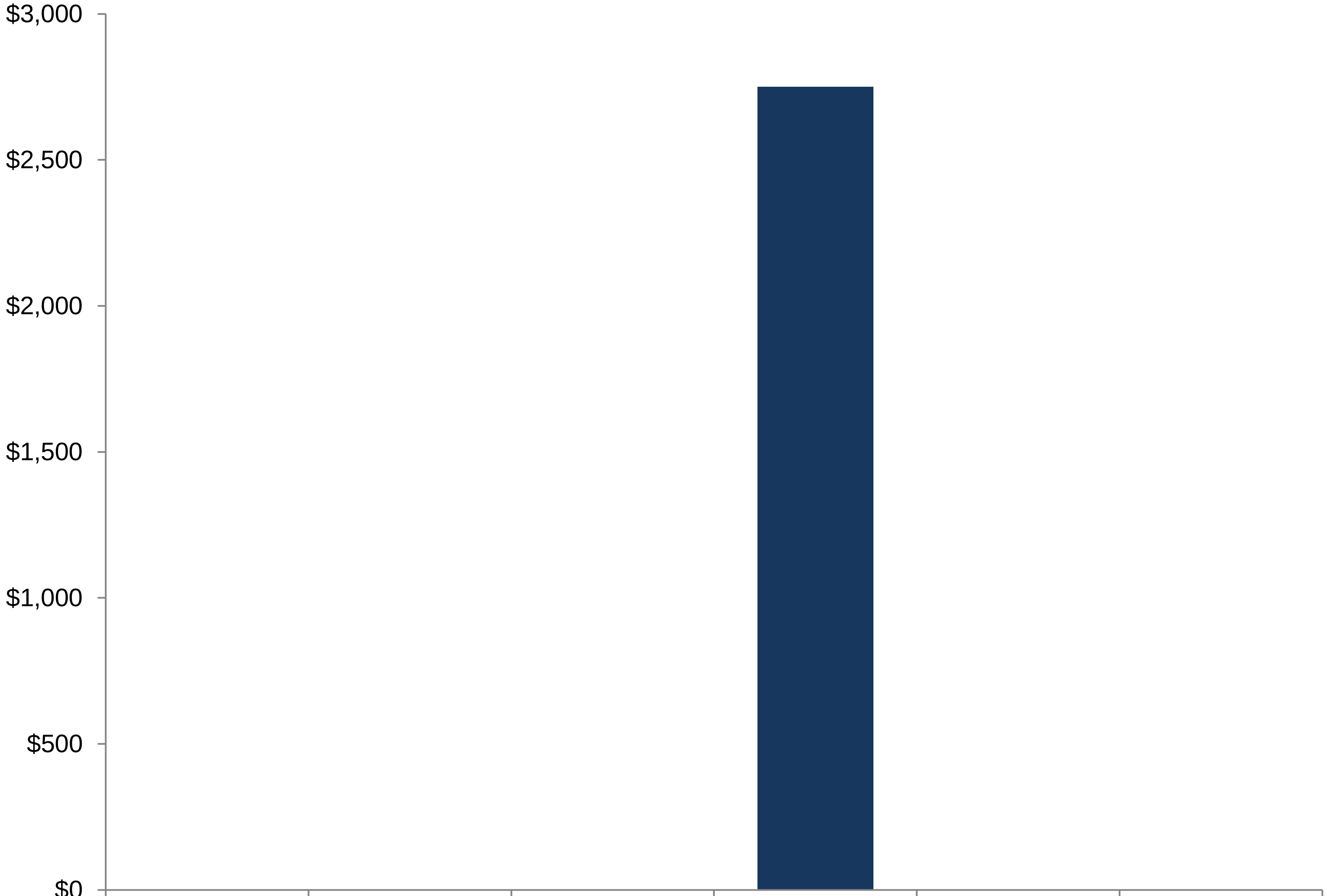
6. CLAIM SUMMARIES

Workers' Compensation Claim Summary



	2013	2014	2015	2016	2017	2018
Total Incurred	$0	$0	$785	$4,566	$0	$0
Claim Count	0	0	2	4	0	0

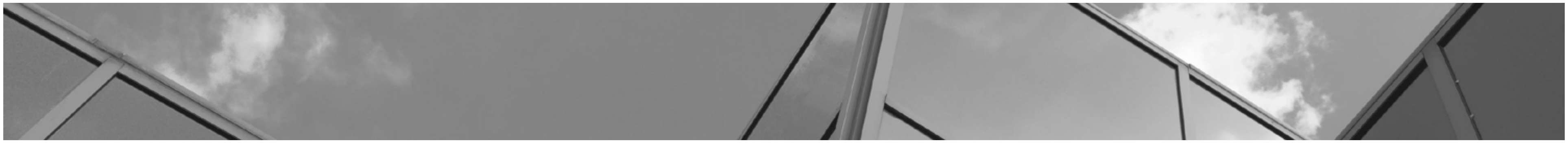
Commercial Auto Claim Summary



	2013	2014	2015	2016	2017	2018
Total Incurred	$0	$0	$0	$2,750	$0	$0

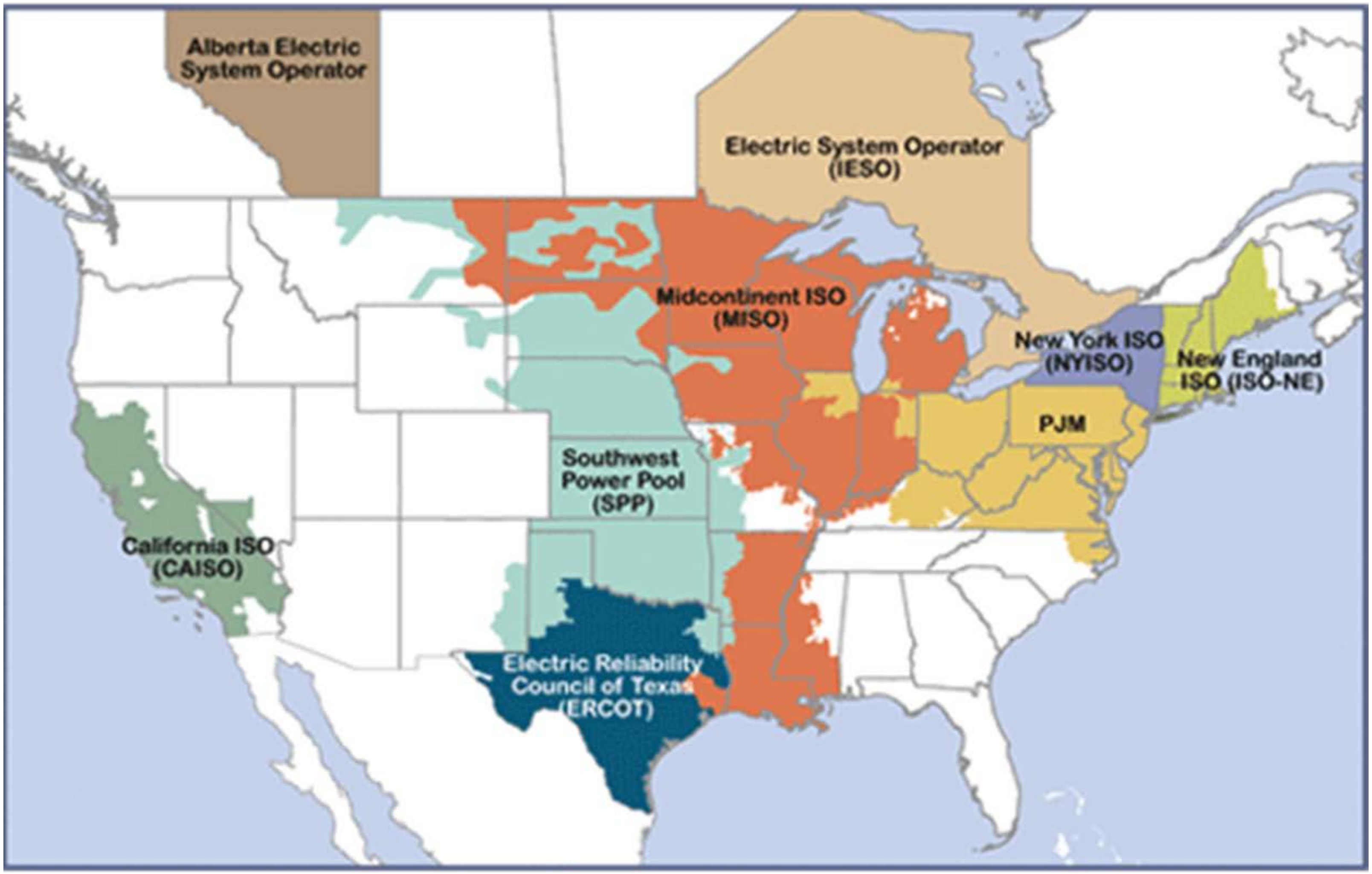
Employment Practices Liability Claims (Number of Reported Claims)

	2013	2014	2015	2016	2017	2018
Claims Reported	1	0	0	0	0	0

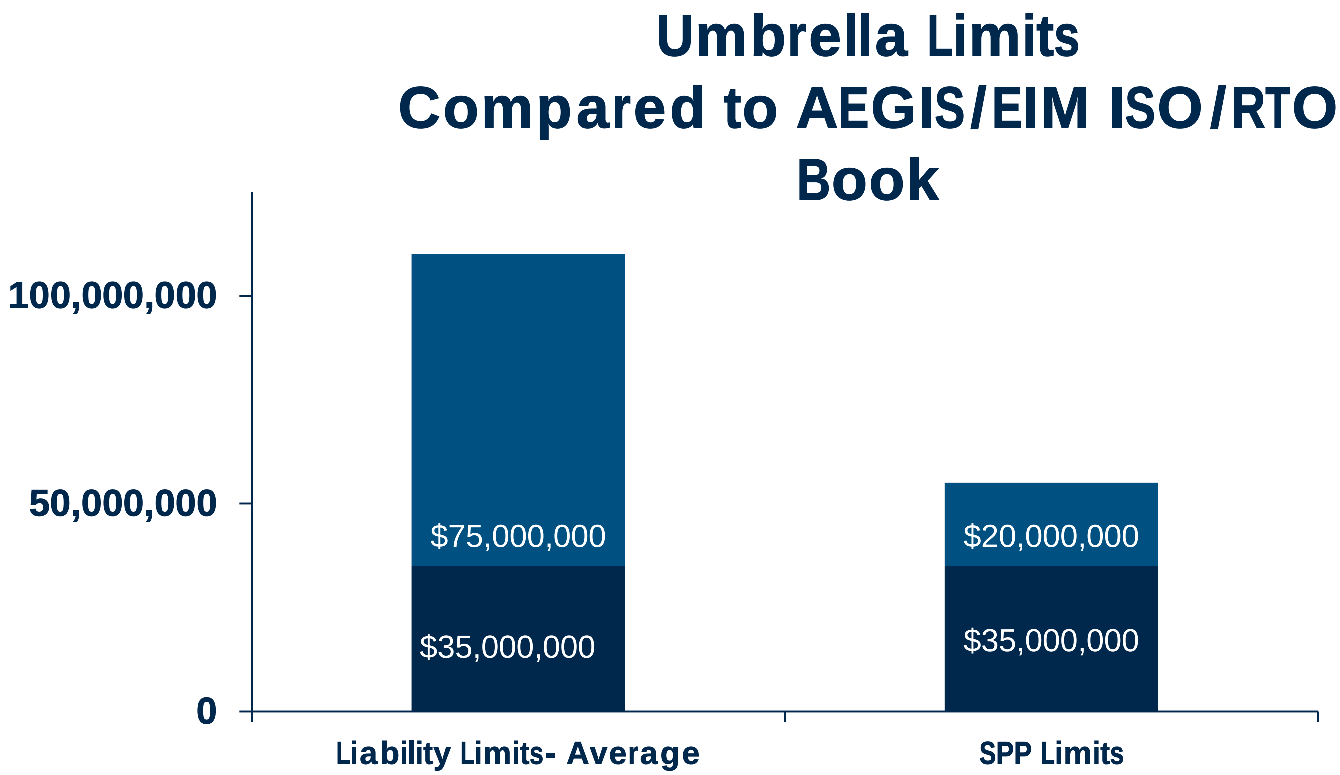


7. BENCHMARKS

Regional Transmissions Organizations



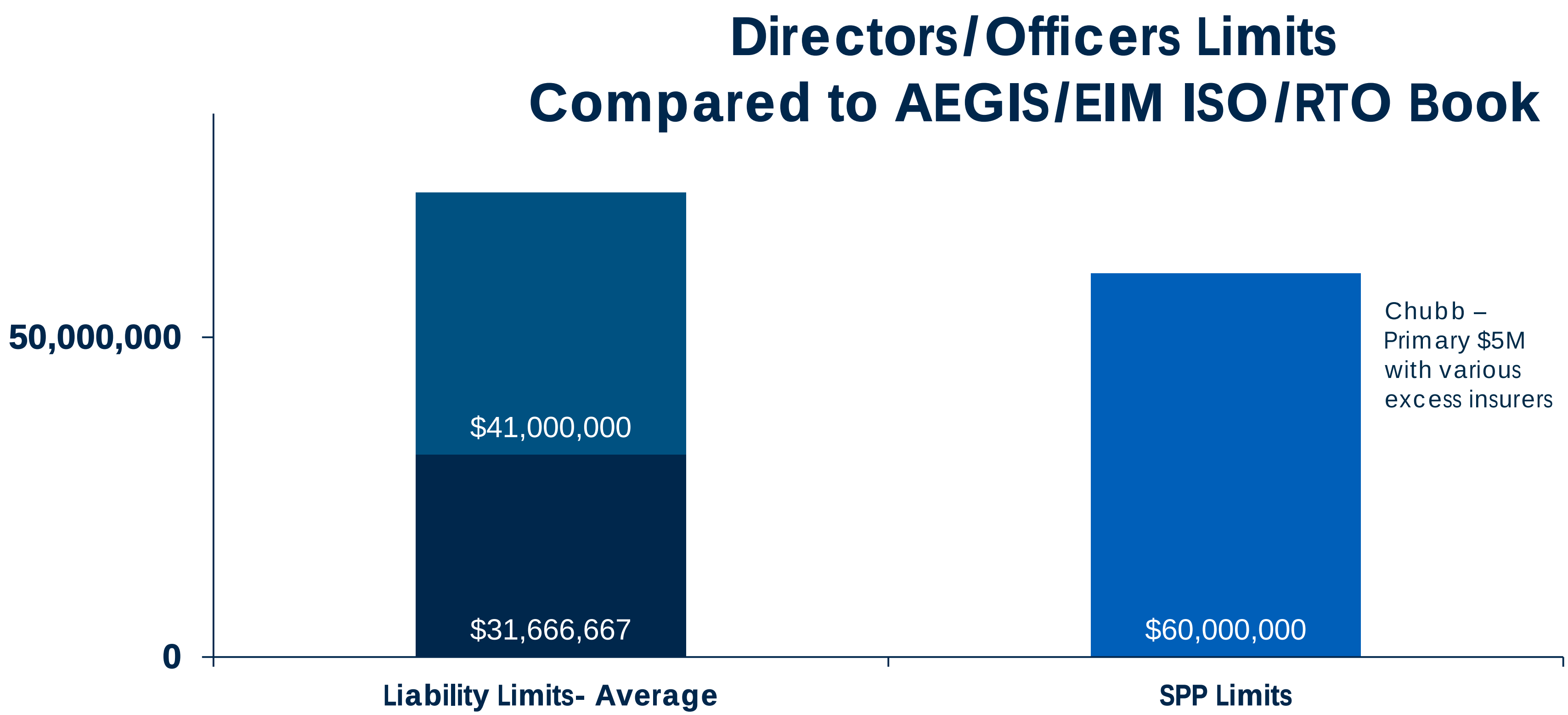
Benchmark – Excess Liability



AEGIS insures nine RTO/ISO's. All carry $35M limits (primary GL/Professional).

EIM insures eight RTO/ISO's. Limits average $75M in excess coverage.

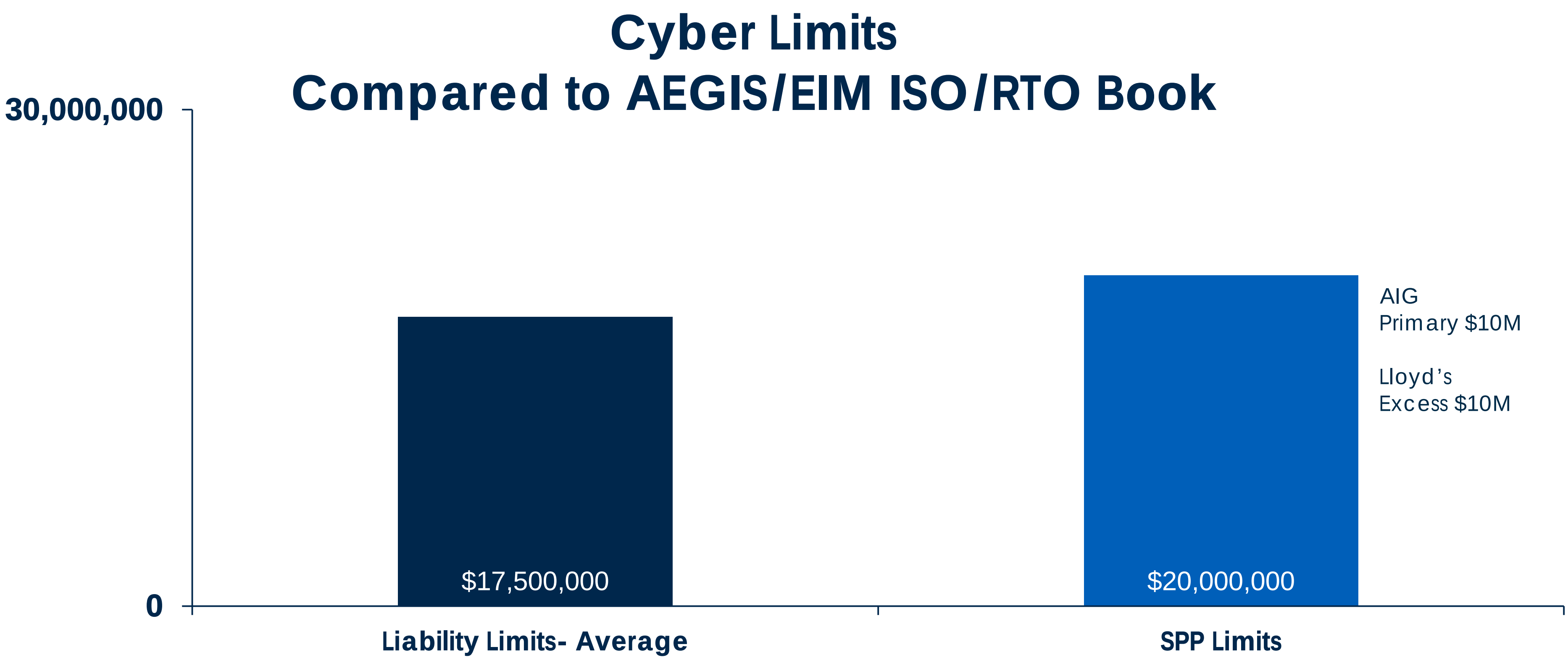
Benchmark – Directors & Officers Liability



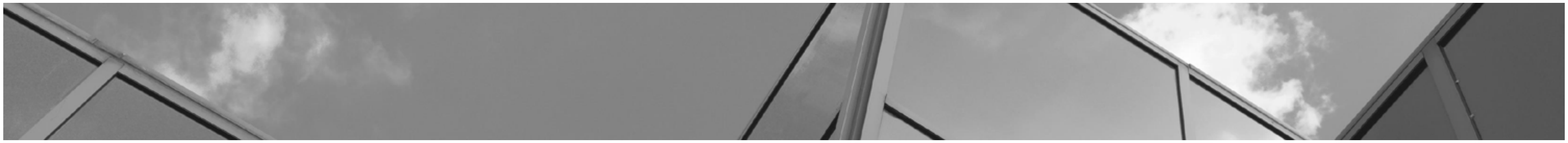
AEGIS insures three RTO/ISO's. Two buy $35M in limits and one buys $25M.

EIM insures four RTO/ISO's. Limits carried vary from $25M to $50M. The average carried is $41M.

Benchmark – Cyber Liability



Of the RTO's insured by AEGIS, two have purchased cyber liability insurance. One has purchased $5M in limits from an outside commercial market and the other has purchased $25M in limits from AEGIS.



8. DISCUSSION ITEMS/RENEWAL PLANNING

2018 Planning & Discussion

- **Renewal expectations for SPP**
  - ❖ **Workers Compensation – Flat**
  - ❖ **Casualty - Flat**
  - ❖ **Umbrella/Excess - Flat**
  - ❖ **Property – Flat**
  - ❖ **Management Liability Flat to +8%**
    - **Deliver Primary Proposal by March 1, 2019**

- **Other Cover Discussion**
  - ❖ **Punitive Wrap**
  - ❖ **Crime**
    - **Traditional coverage, beyond just ERISA**
    - **Workplace Violence**
    - **Social Engineering Fraud**
  - ❖ **Workplace Violence / Active Shooter**
  - ❖ **Patent Infringement (Defense coverage)**

Stephens Social Media

Southwest Power Pool, Inc.

SCHEDULE 1A TASK FORCE

Recommendation to:

Markets and Operations Policy Committee

Finance Committee

Board of Directors

January 28, 2019

Cost Recovery Rate Structure Proposal

Organizational Roster

The following persons are members of the Schedule 1A Task Force:

John Olsen, Evergy (Chair)
Joel Dagerman, NPPD
David Mindham, ITC Holdings Corp.
John Varnell, Tenaska
Rob Janssen, Dogwood Energy
Alfred Busbee, GDS Associates/ETEC
R.J. Tallman, OG&E
Wes Berger, Southwestern Public Service Co.
Ray Bergmeier, Sunflower Electric
Greg Garst, OPPD
Heather Starnes, MJMEUC
Tim Hall, Southern Power
Jason Mazigian, Basin Electric
Jim Jacoby, AEP-Public Service Co. of OK

Background

SPP recovers the vast majority of its operating and capital costs from transmission customers of the tariff based on either prior year average peak demand for network transmission service or reserved capacity for point to point transmission service. This recovery structure was implemented when SPP solely provided transmission service under the tariff. SPP's cost of operation increased with the addition of the Energy Imbalance Services market in 2007 and again in 2014 with the implementation of the Integrated Marketplace. The increases in services and corresponding increase in SPP's operating costs have resulted in several challenges for SPP and its membership which warranted review of SPP's cost recovery mechanism. Principal among these challenges is recovery of SPP costs in retail rates by SPP's load serving transmission customers. Other challenges include a disconnect between those who use and benefit from SPP's services and those who directly pay for SPP's services; and ensuring all who participate in SPP's open and transparent stakeholder processes are incented to ensure the benefits of new initiatives are weighted against the cost to provide those new initiative. The Schedule 1A Task Force (the "Task Force") was formed for the purpose of developing a rate structure that recovers SPP's costs from the various users of SPP's service with the overarching principles of simplicity, better alignment of payer cost/benefit, and inclusion of energy transactions.

Analysis

In arriving at a recommendation, the Task Force performed the following activities:

- Reviewed extensively SPP's cost by the FERC 668 reporting categories
- Examined RTO/ISO cost recovery methodologies for other regions
- Reviewed current Schedule 1A billing processes
- Reviewed multiple iterations of strawman proposals (including staff whitepaper)

- Conducted multiple brain storming sessions on rate design

The Task Force adopted the approach of utilizing the framework provided by FERCs reporting requirement under Order 668. In summary, all operating costs would be evaluated in the categories required to be reported under Order 668 which include 575.7 - Market Facilitation, Monitoring & Compliance, 561.4 - Scheduling, System Control & Dispatch, and 561.8 – Reliability Planning & Standards Development. The Task Force quickly reached general agreement that 1) the proposed structure should use a mix of demand and energy, 2) market costs should be recovered through energy charges, and 3) planning costs should be recovered through demand. Additional discussions were necessary to determine the ultimate recommendation for 1) allocating Scheduling & Dispatch costs, 2) appropriate energy billing determinants, and 3) treatment of financial instruments (e.g. virtuals, TCRs). After additional analyses were performed and related discussions were held, the majority of the Task Force voted to 1) combine Scheduling & Dispatch costs with Reliability Planning to be allocated based on demand (similar to current billing practices); 2) to include real time generation, load, import/exports as energy billing determinants, excluding day ahead metrics; and 3) to include TCRs and virtuals as billable transactions. Utilizing these agreed upon concepts as the foundation, the Task Force arrived at a four rate schedule cost recovery methodology, summarized as follows:

- **Rate Schedule #1**
  Costs to be Recovered – Reliability Planning and Scheduling & Dispatch
  Billing Determinants – prior year 12 CP
- **Rate Schedule #2**
  Costs to be Recovered – TCR Administration (staffing, system maintenance, debt service)
  Billing Determinants - TCRs awarded and converted
- **Rate Schedule #3**
  Costs to be Recovered – Market Clearing (settlements, credit, market monitoring, IT support, customer service)
  Billing Determinants – Real time generation, load, imports/exports, and virtual transactions
- **Rate Schedule # 4**
  Costs to be Recovered – Market Facilitation
  Billing Determinants - Real time generation, load, imports/exports

Recommendation

The Task Force recommends approval of a four rate schedule cost recovery methodology as summarized in the preceding Analysis section.

Approved:	Markets and Operations Policy Committee	January 15, 2019
	3 No (OG&E, OG&E Trans, Flat Ridge 2), 3 Abstain (Tenaska, OMPA, and Gridliance)	
	Finance Committee	
	Board of Directors	
Action Requested:	Approve Recommendation	

Schedule 1A Task Force Update

Finance Committee
January 28, 2019
New Orleans, LA

Task Force Members

John Olsen (Chair)	KCP&L and Westar, Evergy
Wes Berger	Southwestern Public Service Co.
Joel Dagerman	Nebraska Public Power District
Jim Jacoby	AEP-Public Service Co. of OK
David Mindham	ITC Holdings Corp.
John Varnell	Tenaska Power Services Co.
Ray Bergmeier	Sunflower Electric Power Corp.
Greg Garst	Omaha Public Power District
Robert Janssen	Dogwood Energy, LLC
Heather Starnes	Missouri Joint Municipal EUC
Alfred Busbee	GDS Associates/ETEC
Tim Hall	Southern Power
Jason Mazigian	Basin Electric Power Coop.
R.J. Tallman	Oklahoma Gas & Electric

Purpose & Scope of Activities

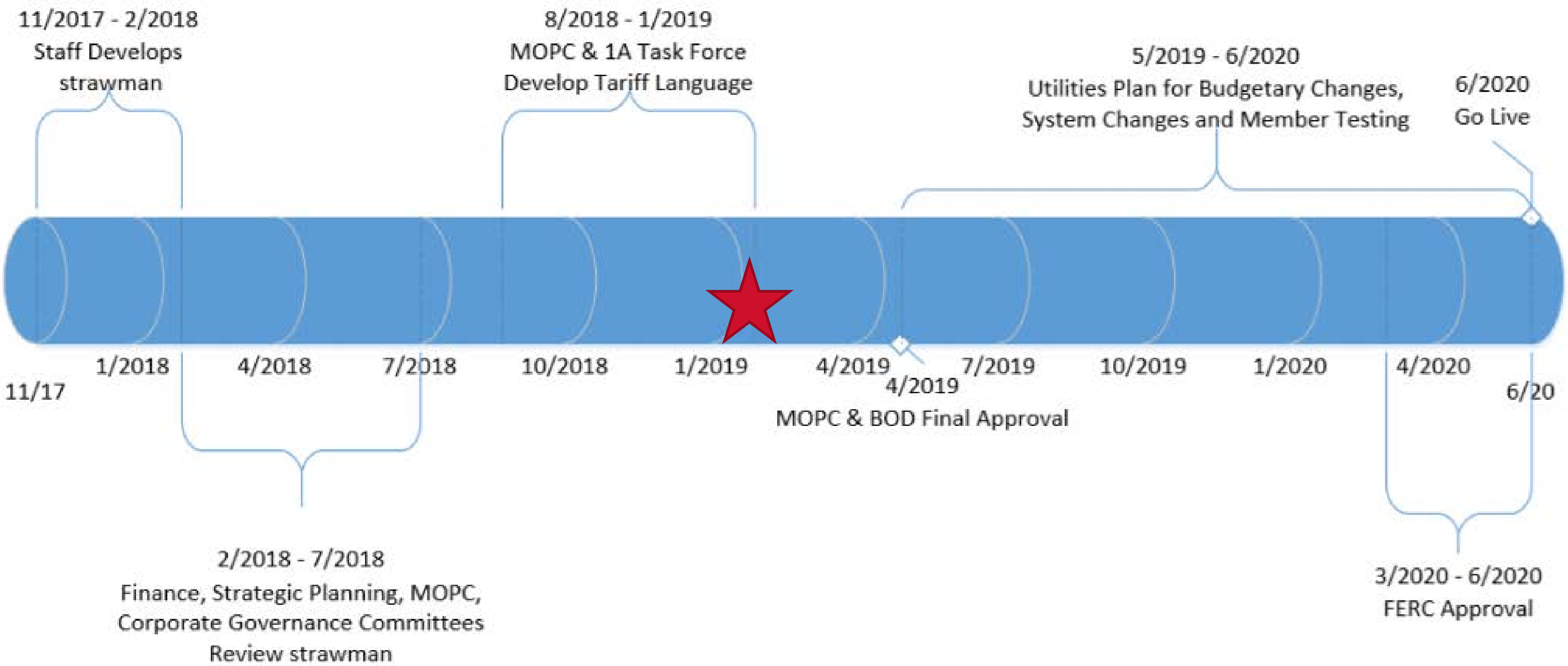
Purpose

- Develop a rate structure that recovers SPP's costs from the various users of SPP's services

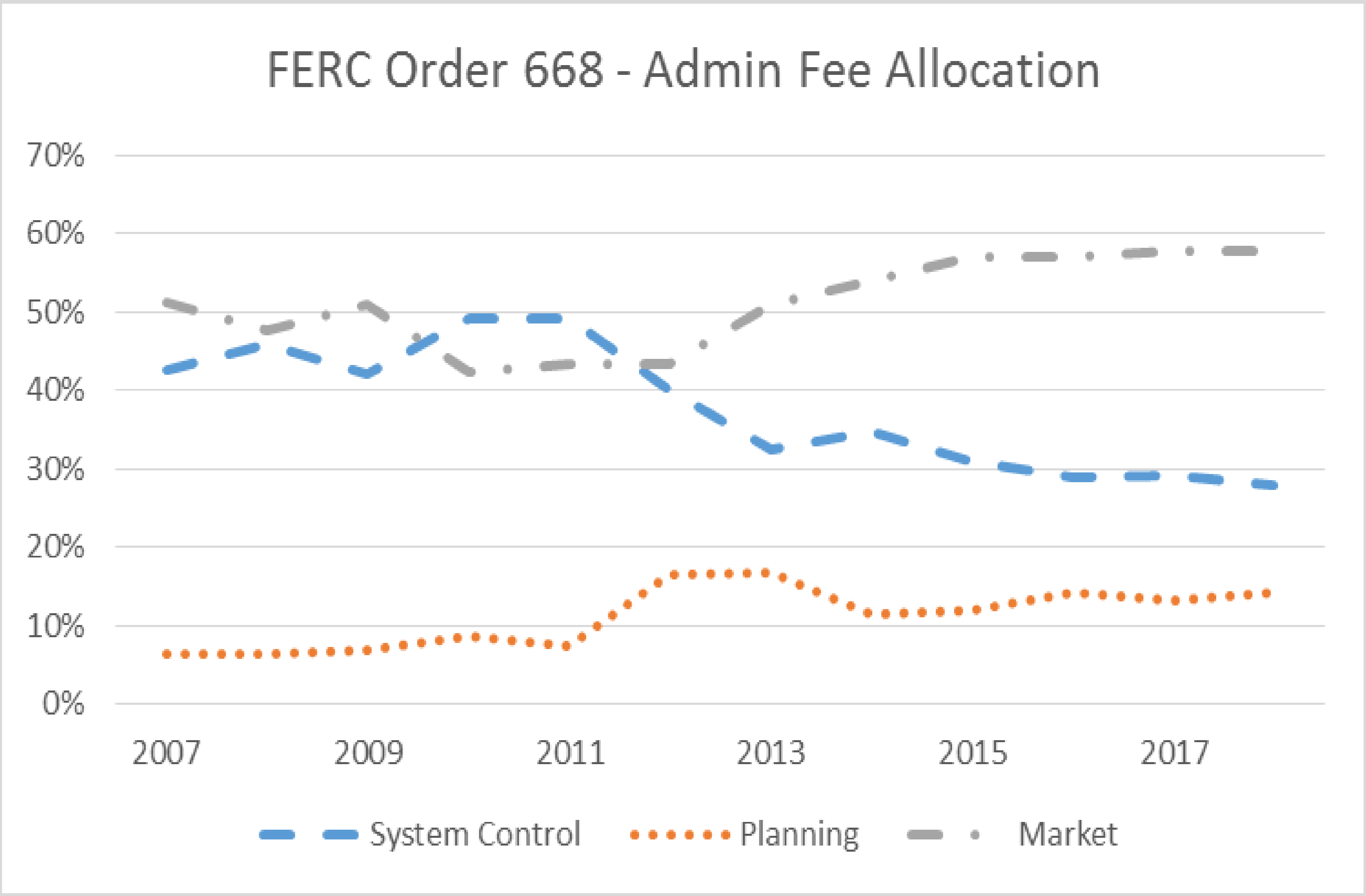
Broad Principles

- Design should be simple to implement/administer
- Better align beneficiary with payer
- Include energy transactions in rate design

Original Timeline



SPP Admin Fee Allocation



Areas of Agreement (and Debate)

- General Agreement
  - Structure to use a mix of demand and energy
  - Market costs recovered through energy charges
  - Planning costs recovered through demand

- Debated Topics
  - Scheduling & Dispatch costs
  - Energy billing determinants
  - Financial instruments (TCRs, Virtuals)

Scheduling & Dispatch Costs

- Majority voted to combine with Planning Costs
  - Systems Operation
  - Operations Support
  - Operations Analysis & Performance Support

- Concerns voiced by "No" votes
  - Dispatch is a service to generators and supply should share in those costs
  - Costs should be based on energy usage rather than demand

SPP

Energy Billing Determinants

- Day Ahead market submittals
- Real time market submittals
- TCR
- ARR
- Virtual transactions
- Imports / Exports

Energy Billing Concerns

- Market behavior impacts
- Perceived discriminatory treatment
- Complexity / increased disputes
- Volatility of billing units
- Market Monitor Opinion

Proposed New Rate Structure

Rate Schedule #	Schedule Description	What Costs are Recovered?	Who Pays?	Billing Determinants
1	**Planning, Scheduling & Dispatch**	FERC Account Categories: -Scheduling & Dispatch -Reliability Planning	Transmission Customers	Prior year 12-month coincident peak (as currently used in Sch 1A)
2	**TCR Administration**	Costs for administering TCR process	TCR Participants	All TCRs awarded and converted from ARRs
3	**Market Clearing**	Costs associated with clearing, monitoring, and settling market transactions	Virtual and Real-Time Market Participants	Real time gen, load, imports/exports, and virtual transactions
4	**Markets Facilitation**	Remaining market costs, not recovered in rate schedule #2 and #3	Real-Time Market Participants	Real time gen, load, & imports/exports

SPP

Proposed New Rate Structure

	Rate Schedule #1		Rate Schedule #2		Rate Schedule #3		Rate Schedule #4	
	Planning and Scheduling & Dispatch		TCR Admin		Market Clearing		Markets Facilitation	
Total Costs	$64.0	MM	$4.4	MM	$19.0	MM	$64.3	MM
Denominator	382	TWh	547	TWh	563	TWh	528	TWh
Rate	$0.167	/ MWh	$0.008	/ MWh	$0.034	/ MWh	$0.122	/ MWh

NOTES:

- **<u>2017 actual results</u>** were utilized for Total Costs in this analysis
- 12CP Data (utilized for Rate Schedule 1) represents the estimate from the 2018 budget.
- Market metrics (utilized for Rate Schedules 2-4) were taken from the 2017 actual results as reported by settlements.

SPP

Current vs Proposed Rate Schedules

(All Dollars in MMs)

	Current Method	New Schedules	New vs Current	New vs Current
Entity Type	**Total 1A Fees**	**Total RSs 1-4**	**Inc/(Dec) $s**	**Inc/(Dec) %**
Cooperatives	$28.8	$24.0	($4.8)	-17%
Federal Agencies	$4.3	$4.4	$0.0	1%
Independent Power Producers	$6.4	$8.9	$2.5	39%
Investor-Owned	$82.8	$81.3	($1.5)	-2%
Marketers	$0.7	$4.6	$3.9	561%
Municiples/State Agencies	$28.5	$28.4	($0.1)	0%
TOTAL	**$151.6**	**$151.6**	**$0.0**	

NOTE:
2017 settlements data was utilized for purposes of this comparative analysis.

Current vs Proposed Rate Schedules

(All Dollars in MMs)

	Current Method		Proposed Method		Variance
Entity Type	**Total 1A Fees**	**% of Total**	**TOTAL RSs 1-4**	**% of Total**	**% Inc/(Dec)**
Cooperatives	$28.8	19%	$24.0	16%	-3%
Federal Agencies	$4.3	3%	$4.4	3%	0%
Independent Power Producers	$6.4	4%	$8.9	6%	2%
Investor-Owned	$82.8	55%	$81.3	54%	-1%
Marketers	$0.7	0%	$4.6	3%	3%
Municiples/State Agencies	$28.5	19%	$28.4	19%	0%
TOTAL	**$151.6**	**100%**	**$151.6**	**100%**	**0%**

NOTE:
2017 settlements data was utilized for purposes of this comparative analysis

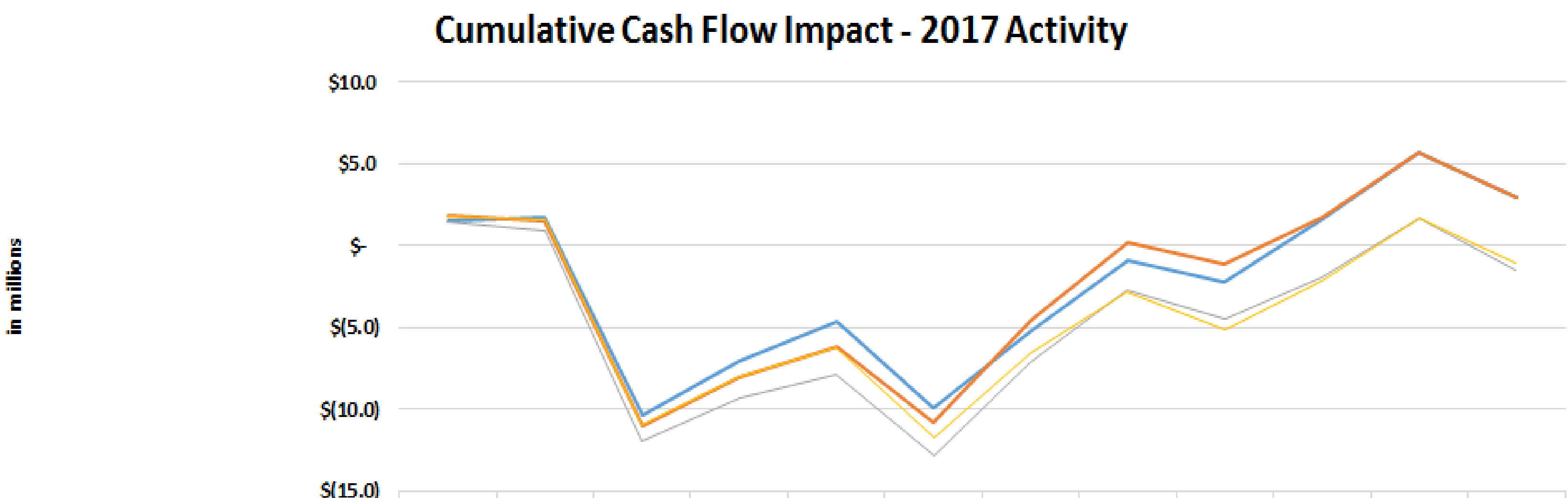
SPP

Cash Flow Analysis

- Examined monthly cash flows for the following scenarios –
  1) 2016 and 2017 Actual Results
  2) Proposed Rate Structure w/ actual billing determinants
  3) Proposed Rate Structure Assuming 5% decrease in all market billing determinants across all months
  4) Proposed Rate Structure Assuming 5% annual decrease in generation/load billing determinants in June – September only.
- Analyzed cumulative impact on net cash flows for each scenario.

SPP

2017 Cash Flow Analysis



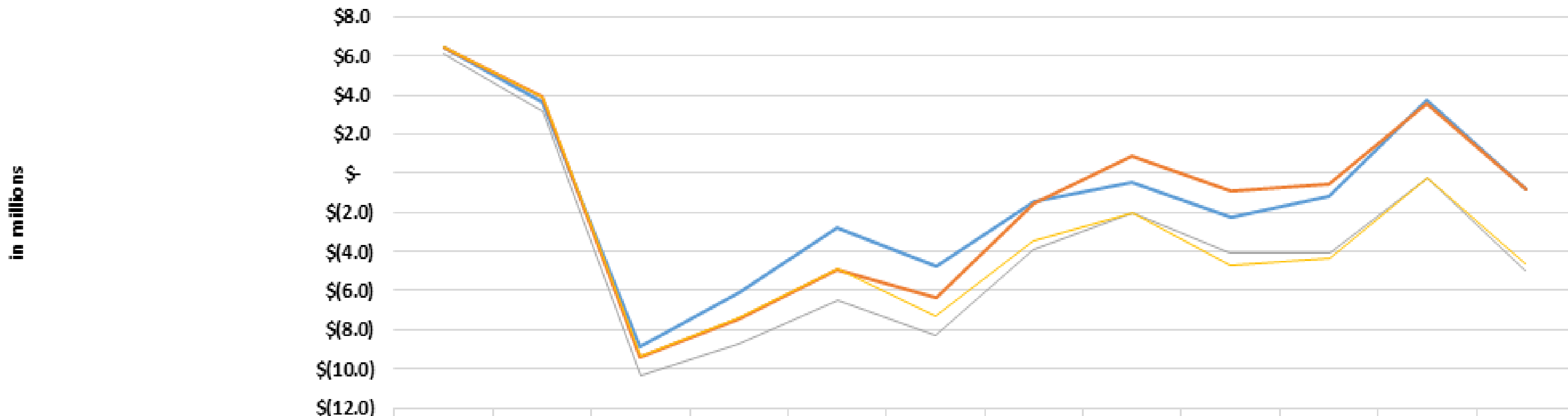
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Actual Net Cash Flows	$1.5	$1.7	$(10.4)	$(7.1)	$(4.7)	$(10.0)	$(5.2)	$(0.9)	$(2.2)	$1.6	$5.7	$2.9
Proposed Rate Structure	$1.8	$1.5	$(11.0)	$(8.0)	$(6.2)	$(10.8)	$(4.6)	$0.2	$(1.2)	$1.7	$5.6	$2.9
Proposed w/ 5% decrease	$1.4	$0.8	$(12.0)	$(9.4)	$(7.9)	$(12.9)	$(7.1)	$(2.8)	$(4.5)	$(1.9)	$1.6	$(1.5)
Proposed w/ 5% decrease in June-Sept	$1.8	$1.5	$(11.0)	$(8.0)	$(6.2)	$(11.8)	$(6.6)	$(2.8)	$(5.1)	$(2.2)	$1.7	$(1.1)

NOTE:
Results represent cumulative cash flows (net of cash outflows) for each scenario

SPP

2016 Cash Flow Analysis

Cumulative Cash Flow Impact - 2016 Activity



	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Actual Net Cash Flows	$6.4	$3.7	$(8.9)	$(6.1)	$(2.8)	$(4.8)	$(1.5)	$(0.5)	$(2.3)	$(1.2)	$3.8	$(0.8)
Proposed Rate Structure	$6.5	$3.9	$(9.4)	$(7.4)	$(4.9)	$(6.3)	$(1.5)	$0.8	$(0.9)	$(0.6)	$3.6	$(0.8)
Proposed w/ 5% decrease	$6.1	$3.2	$(10.4)	$(8.7)	$(6.5)	$(8.3)	$(3.9)	$(2.0)	$(4.1)	$(4.1)	$(0.2)	$(5.0)
Proposed w/ 5% decrease in June-Sept	$6.5	$3.9	$(9.4)	$(7.4)	$(4.9)	$(7.3)	$(3.4)	$(2.0)	$(4.7)	$(4.4)	$(0.2)	$(4.6)

NOTE:
Results represent cumulative cash flows (net of cash outflows) for each scenario

SPP

Cash Flow Analysis

- Observations

1) Seasonality in cash outflows exist today with notable spikes at quarter end (primarily due to debt payments)
2) Seasonal cash flow decreases noted in 2016 and 2017 actuals are representative of historical trends
3) Cash flow position under proposed scenarios does not materially improve or worsen in comparison to actual results under current Schedule 1A methodology
4) Consistent with current practices, seasonal spikes can be managed with existing, short term financing arrangements

SPP

MOPC Approval

- At their January 15th meeting, MOPC approved the following recommendation from the Schedule 1A Task Force -

  MOPC to approve the four rate schedule cost recovery methodology as summarized by the Schedule 1ATF presentation

- Three opposing votes
  OGE, OGE Transmission, Flat Ridge 2
- Three abstentions
  Tenaska, OMPA, and Gridliance

Recommendation to Finance Committee

Schedule 1A Task Force is seeking approval from the Finance Committee of the recommended four rate schedule cost recovery methodology as summarized in this presentation.

Future Meetings/Deliverables

- January 28-29 – Proposed structure presented to Finance Committee and Board for approval
- February 5 – 1ATF Meeting Dallas (DFW Hyatt)
  - Determine rate setting/true-up frequency
  - Finalize proposed tariff revisions
- Feb–March 2019 – Proposed tariff revisions to be reviewed and approved by RTWG
- April 2019 - MOPC approval of tariff revisions

SPP

Appendix

Schedule 1A Task Force Update

Finance Committee
January 28, 2019
New Orleans, LA

Proposed Rate Schedule # 1

Planning and Scheduling & Dispatch		
Reliability Planning	$21.6	MM
Scheduling & Dispatch	$42.3	MM
TOTAL COSTS	$64.0	
12CP Billing Determinants	382	TWh
Planning and Scheduling Rate	$0.167	/ MWh

Proposed Rate Schedule # 1

➢Final Voting Results

For – 10
Against – 2
Abstain – 2

➢Dissenting Opinions

- OG&E – Is not convinced that the denominator for RS 1 is correct for these costs, further stating that dispatch is a service to generators and that supply should share in the costs for SPP providing that function.

- OPPD – Believes that the scheduling and dispatch costs should be based on energy usage (RS 4) rather than demand (RS 1).

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Proposed Rate Schedule # 2

TCR Administration		
TCR Administration Costs	$4.4	MM
TCRs Awarded & Converted	547	TWh
TCR Administration Rate	$0.008	/ MWh

SPP

Proposed Rate Schedule # 2

- **Final Voting Results**
  For – 11
  Against – 2
  Abstain – 1

- **Dissenting Opinions**
  - AEP (PSCO) - Did not agree that the denominator should include all "TCRs awarded or converted" and specifically noted that TCRs converted from ARRs should be excluded given that ARRs have already been paid through transmission service charges, and therefore should be excluded from this separate TCR administrative charge.
  - NPPD – Preferred a denominator that included only those TCR volumes that exceed the load values for a specific settlement location, which represents those TCRs that are in excess of hedges for native load. Using this approach would provide for a reasonable compromise to ensure fair but not excessive costs and would preclude any unnecessary double "administrative" billing to hedge native load.

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Proposed Rate Schedule # 3

Market Clearing		
Market Monitoring	$3.0	MM
Settlements	$2.8	MM
Information Technology (allocation)	$2.4	MM
Credit	$0.7	MM
Customer Relations (allocation)	$0.9	MM
Clearing Overhead	$9.2	MM
Market Clearing Costs	$19.0	MM
Real Time Generation	260	TWh
Real Time Load	250	TWh
Real Time Import/Export	18	TWh
Virtual Energy	35	TWh
Market Clearing Denominator	563	TWh
Market Clearing Rate	$0.034	/ MWh

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Proposed Rate Schedule # 4

Market Faciliation		
Market Facilitation	$87.6	MM
Less: TCR Admin Costs	($4.4)	MM
Less: Market Clearing Costs	($19.0)	MM
Market Facilitation Costs	$64.3	MM
Real Time Generation	260	TWh
Real Time Load	250	TWh
Real Time Import/Export	18	TWh
Market Denominator	528	TWh
Market Facilitation Rate	$0.122	/ MWh

SPP

Proposed Rate Schedules 3 and 4

- **Final Voting Results**

  For – 10
  Against – 1
  Abstain – 1

- **Dissenting Opinion**

  - Xcel (SPS) – While in agreement on the components of the numerator and denominator, representative believes that it would be more appropriate to use the maximum of the Day-ahead and Real-time for the denominator as opposed to simply using Real-time.

SPP

Southwest Power Pool

Memorandum

To: **SPP Finance Committee**

From: **Tom Dunn**

CC:

Date: **January 15, 2019**

Re: **Actuarial Assumptions for Pension Valuation**

The SPP Finance Committee, at its April 2013 meeting, requested SPP staff provide an early look at assumptions utilized in valuation of SPP's pension plan and post-retirement healthcare plan. This memo provides that look at the four major assumptions: discount rate, long-term rate of return, compensation change rate, and mortality tables.

Discount Rate: The SPP Finance Committee, at its April 2008 meeting, concurred on a process to set the discount rate used in valuing pension liabilities. In general, the method used to set the discount rate follows the framework described in the Pension Protection Act of 2006. Section 102 of Title I of the Pension Protection Act of 2006 defines interest rates for determining the funding targets of covered plans. These interest rates are based on the Corporate Bond Yield Curve prescribed by the U.S. Treasury Department and reflect the twenty four month average of investment grade corporate bonds (the top three rating tranches).

Also described in the Pension Protection Act of 2006 are three Segment Rates that can be used for the purpose of assigning a discount rate. These rates are differentiated based on the maturities of the corporate bonds underlying the yield curves used to determine each rate. The segments are broken down as follows:

1. First – zero through five years
2. Two – six through fifteen years and
3. Three – greater than fifteen years

The final issue to address is the selection of a Segment Rate for the SPP plan. One of the most pertinent demographic points to consider here is that the average age of the participants in the SPP retirement plan is less than 45 years. This would indicate that major distributions from the plan should not begin occurring, on average, for another twenty years.

The Internal Revenue Service publishes periodic updates to segment rates throughout the year. The most recent update, published December 2018 indicated 24-month average segment rates of 2.50%/3.92%/4.50%. SPP used a discount rate of 5.00% in 2018. **SPP staff recommends a discount rate to 5.00% going forward, in line with the 3rd segment discount rate.** While this recommendation appears a bit more aggressive than the 3rd segment rate as of December 2018, the first and second segment rates have already experienced increases over the prior year's report due to the fed funds rate increases instituted by the U.S. Federal Reserve Bank.

Long-term Rate of Return: The SPP Finance Committee, at its April 2008 meeting, concurred on a process to set the long-term rate of return used in pension valuation. The method used by SPP to assign the long-term rate of return is based upon an analysis of the long-term returns of widely recognized benchmark investments similar in asset allocation to the investments held in the pension plan trust. The benchmark returns are weighted based on SPP's desired asset allocation described in the Investment Policy Statement.

The Russell 3000 Index measures the performance of the largest 3000 U.S. companies representing approximately 98% of the investable U.S. equity market. The Russell 3000 Index is constructed to provide a comprehensive, unbiased, and stable barometer of the broad market and is completely reconstituted annually to ensure new and growing equities are reflected. The Bloomberg Barclays Government/Credit Bond Index is a non-securitized component of the Bloomberg Barclays U.S. Aggregate

Index. The U.S. Government/Credit Index includes U.S. Treasury with remaining maturities of more than one year, U.S. government-related issues (agency, sovereign, local authority, supranational) and corporate issues.

	Russell 3000	Barclays Gov't/Credit Index
15 Year Return (1/1/2003 – 12/31/2018)	9.21%	
10 Year Return (1/1/2008 – 12/31/2018)	7.26%	2.09%
Target Allocation	70%	30%
Weighted Avg. Return	6.45%	0.63%
Historical Expected Portfolio Return	**7.08%**	

SPP used a long-term rate of return assumption of 7.00% in 2018. **SPP staff recommends retaining the long-term rate of return at 7.00%**

Compensation Change Rate: SPP's year over year growth rate in compensation has significantly exceeded the long-term growth rate of 4% SPP has used in its pension valuation. SPP expects compensation growth to slow absent unforeseen growth in total staffing levels. A 4% long-term growth rate is consistent with that used by many of SPP's members in their pension plan evaluations and is consistent with the compensation changes for 2019 approved by the SPP Human Resources Committee (3% increase in base compensation and 0.75% funding for non-standard and promotion increases). **SPP will use the 4.00% compensation rate change for the upcoming valuation.**

Pension Mortality Table: The SPP Finance Committee, at its December 7, 2015 meeting, determined a preference to maintain the mortality table consistent with the table used by the U.S. Internal Revenue Service. The IRS updates its mortality tables annually. SPP utilized the IRS-2018 table for its prior valuation. **SPP will use the IRS-2019 table for the upcoming valuation.**

Southwest Power Pool, Inc.
FINANCE COMMITTEE
Recommendation to the SPP Board of Directors
January 28, 2019

Organizational Roster

The following persons are members of the Finance Committee:

Bruce Scherr	Director
Susan Certoma	Director
Sandra Bennett	American Electric Power
Laura Kapustka	Lincoln Electric System
Jerry Peace	Oklahoma Gas & Electric
Mike Wise	Golden Spread Electric Coop

Background

SPP's term debt structure as of the end of December 2018 was as follows:

Due Date	Rate	Balances ($MM) Original	Balances ($MM) Current	Funding Year	Lender	Primary Purpose
2027 Sr. Notes	5.51%[1]	$ 5.1	$ 2.7	2007	Bank	Maumelle Facility
2042-A&B Sr. Notes	4.82%	$ 65.0	$ 58.3	2010	Insurance	Corporate Campus
2024-C Sr. Notes	3.55%	$ 70.0	$ 36.8	2011	Insurance	Integrated Marketplace
2024-D-1 Sr. Notes	3.00%	$ 50.0	$ 26.3	2012	Insurance	Integrated Marketplace
2024-D-2 Sr. Notes	3.25%	$ 50.0	$ 28.8	2012	Insurance	Integrated Marketplace
2025-E Sr. Notes	3.80%	$ 37.0	$ 37.0	2014	Insurance	Project Pinnacle
2024 Floating Note	3.23%[1]	$ 33.0	$ 24.8	2014	Bank	Capex Program
2028 Credit Facility	Multi[2]	$ 80.0	$ 0.3	2018	Bank	Capex Program
	Totals	$ 390.1	$ 214.5			

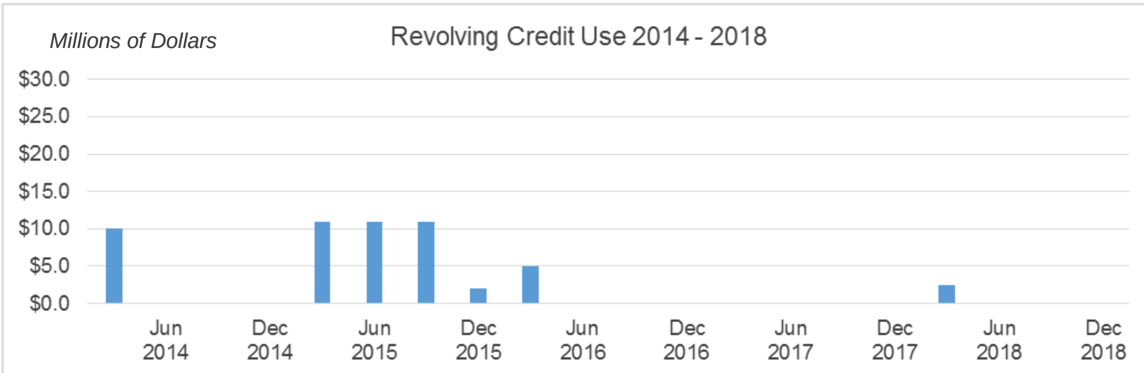
All notes are unsecured except for the 2027 senior notes which are secured by a first mortgage on SPP's Maumelle, AR operations facility. SPP also has available a $30 million unsecured revolving line of credit maturing October 2019. The line is used to support a 6-month debt service reserve required by SPP's term credit agreements and to provide a temporary liquidity resource. Draws under the revolving facility are priced at LIBOR + 125bps. SPP pays a 12.5bp per year unused commitment fee on this facility.

[1] Swap agreements were established to hedge interest rate risk on certain floating rate debt obligations. Rates identified reflect the fixed rate obligations.

[2] The 2028 Credit Facility includes two components: 1) a 5-year revolving master note priced at LIBOR + 150bps with a floor of 2.75%, and 2) the ability to periodically convert draws from the revolver into 4-year term notes with fixed rates based upon 5-year treasuries + 185bps. As of December 2018, SPP had drawn $0.3 million on the revolver and had no fixed note tranches.

Analysis

SPP's revolving line of credit matures in October 2019 and has no outstanding balance as of December 31, 2018. Usage under the line has been minimal over the last few years, as illustrated in the following chart showing outstanding balances at month end.



SPP's operating cash flow is comprised of a once a month cash inflow with outflows occurring weekly. Inflows arrive in the form of Schedule 1A revenues collected monthly which remain relatively flat throughout the year. Outflows are generally higher in the first quarter of each year primarily due to annual maintenance and insurance prepayments. Since SPP operates on a net zero basis, the first quarter variability can be meaningful with respects to availability of operating funds.

The lender has offered to extend the expiration date for an additional two years with the same terms and conditions and with no additional legal, closing or origination fees. During the original request for proposal period, other responding banks quoted up to $75 thousand in origination fees if selected. Based on prior experience, SPP staff contends the most cost effective approach is to renew with the existing lender.

Recommendation

Approve extension of maturity date of $30 million revolving credit facility to October 2021 with all other terms and conditions remaining unchanged. Authorize the SPP President and Chief Financial Officer to execute documentation to effectuate the renewal.

Approved: SPP Finance Committee

Action Requested: Approve Recommendation


SPP Southwest Power Pool
HELPING OUR MEMBERS WORK TOGETHER
TO KEEP THE LIGHTS ON... TODAY AND IN THE FUTURE.

Southwest Power Pool

Recent RTO Credit Default

January 28, 2019

SouthwestPowerPool SPPorg southwest-power-pool

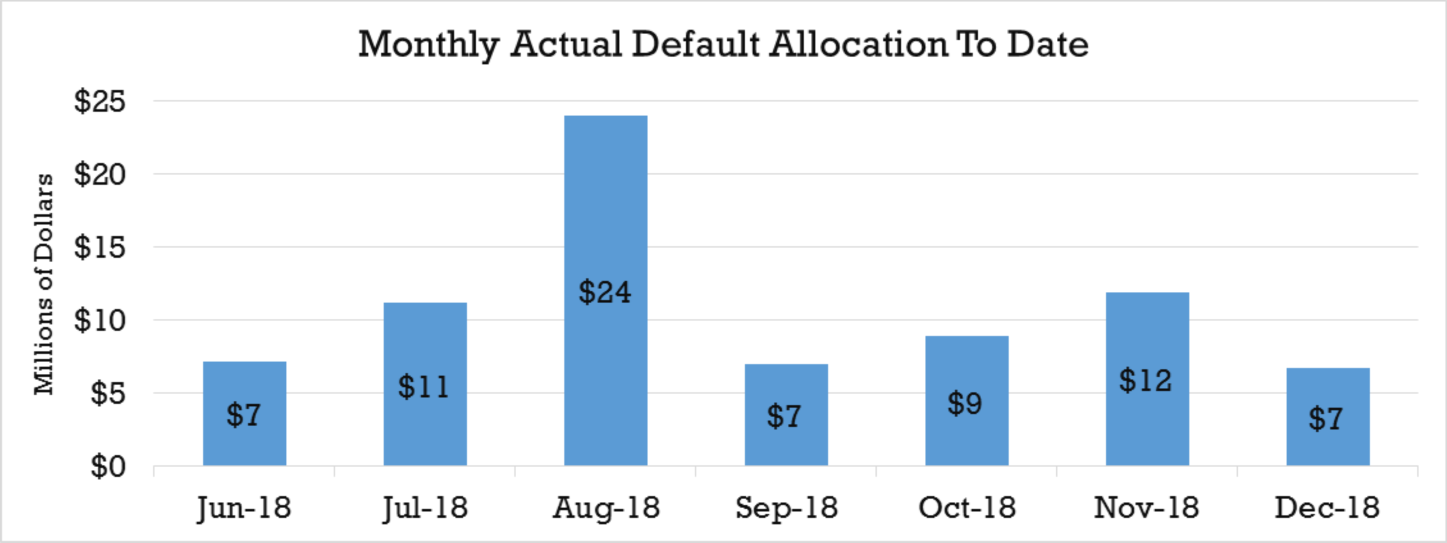
PJM Credit Default

- Since 2015, GH acquired a 890 million MWh FTR (TCR) long-term portfolio
  - Portfolio initially indicated as highly profitable
- PJM transmission upgrades changed congestion flows eroding Green Hat portfolio value
- PJM declared GreenHat Energy, LLC in default of credit policy on June 21, 2018
  - *Failed to pay invoice and cure a collateral call*

SPP

PJM Credit Default

- GreenHat's Andrew Kittell & John Bartholomew (formerly JPMorgan) were involved in a FERC market manipulation settlement of $410MM in 2013
  - *SPP has no exposure to these two individuals*
- Total estimated loss: $185MM



SPP

SPP Differences with PJM

- SPP does not have true long-term TCRs
  - SPP's TCRs extend to one plan-year
- SPP's system is not as congested as PJM's
- SPP's valuation of historically negative TCRs is more conservative
- SPP only allocates a portion of the transmission system during annual auction

Stakeholder Discussions

- Background checks on principals of registering market participants
- Stakeholder review of Credit Policy and exposure calculations
  - MMU involved in this effort
- Out of the box thinking

Monthly Financial Reporting Package
December 2018
Preliminary & Unaudited

Southwest Power Pool

SPP Executive Summary – December

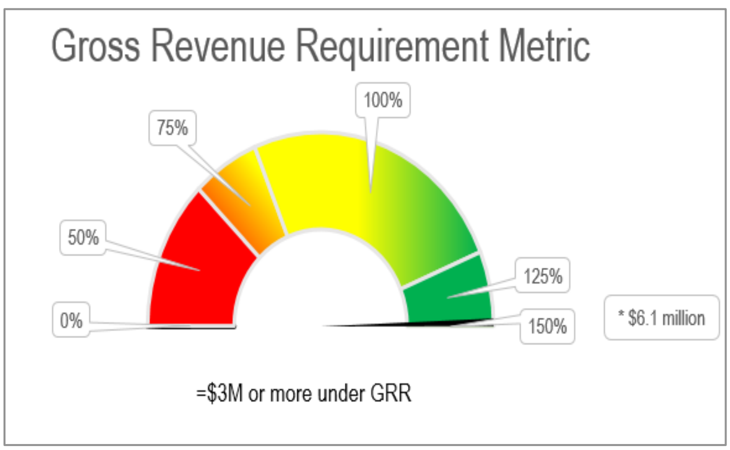
2018 Over / (Under) Recovery

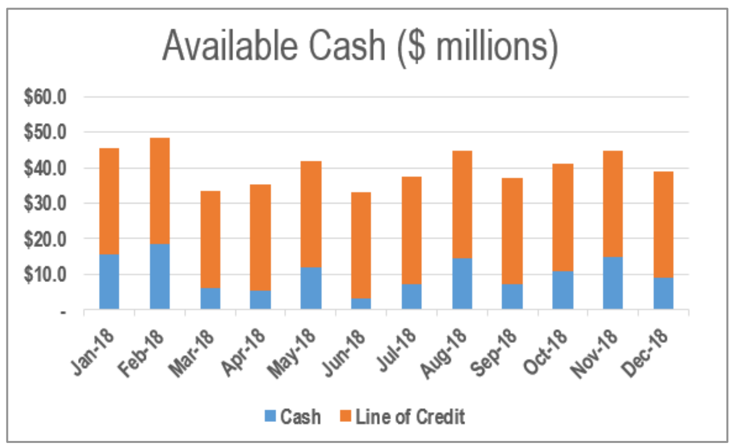
Cost Recovery ($ millions)	2018 Actual	2018 Budget	Fav/ (Unfav)
Gross Revenue Requirement (GRR) *	$161.8	$167.9	$6.1
Net Revenue Requirement (NRR)	152.2	164.0	11.8
Admin Fee Revenue	165.0	164.0	1.0
Over / (Under) Recovery	$12.8	($0.0)	$12.8

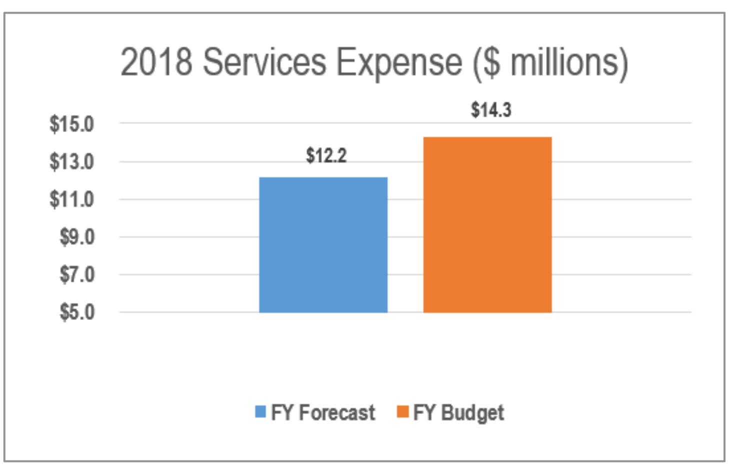
* GRR for HR metric excludes FERC fees and Regional Entity expenses

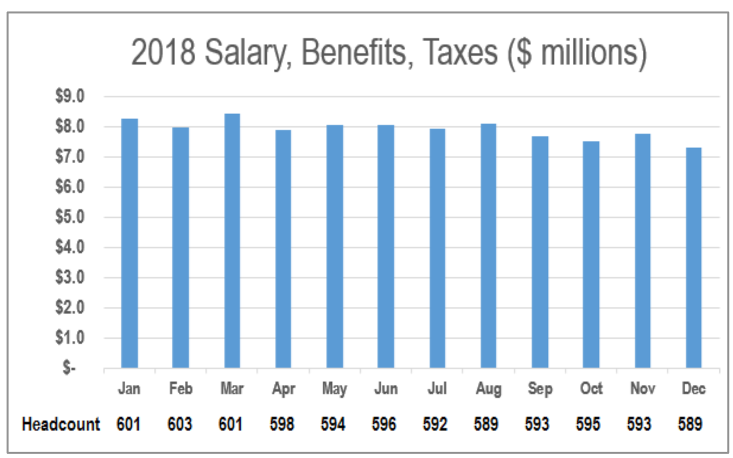
Note: Notable changes from prior month include various annual employee benefits true-ups (favorable to NRR/over-recovery).

GRR & Available Cash, Compensation and Outside Services Expenses









Southwest Power Pool
2018 Financial Commentary
December 31, 2018
2018 Preliminary and Unaudited
(in thousands)

Summary

	2018 FY Actual	2018 FY Budget	Fav/(Unfav) Variance	
Revenues	$198,904	$194,212	$4,692	2.4%
Expenses	183,945	190,752	6,806	3.6%
Net Income/(Loss)	$14,959	$3,460	$11,498	(332.3%)

Revenue

	2018 FY Actual	2018 FY Budget	Fav/(Unfav) Variance	
Tariff Administration Service	$164,969	$164,001	$968	0.6%
FERC Fees & Assessments	20,991	20,769	222	1.1%
NERC ERO Regional Entity Revenue	5,319	4,724	595	12.6%
Miscellaneous Income	6,187	3,963	2,224	56.1%
Contract Services Revenue	856	156	701	449.8%
Annual Non-Load Dues	582	600	(18)	(3.0%)
Total Revenue	$198,904	$194,212	$4,692	2.4%

The annual billing determinants for the 2018 budget were based on year-to-date actual data as of July 2017, with assumptions for peak demand for the months of August through December. The billing determinants associated with Tariff Administrative Service revenue is 384 million MWh as compared to the budgeted amount of 382 million MWh, which results in a slightly favorable variance to budget.

NERC Revenues exceed budget primarily due to revenue associated with certain compensation expenses (such as retention and unused vacation pay) related to the dissolution of the Regional Entity that were not contemplated in the budget. The budget also assumed a dissolution date of June 30th, whereas the actual date was August 31st. The increase in NERC revenues is partially offset by the increase in RE expenses.

Miscellaneous Income primarily includes revenues associated with engineering studies along with various other revenue sources such as the MISO settlement, miscellaneous rebates, reserve sharing, IM virtual fees, and circuit reimbursements.

The favorable variance is primarily related to increased revenues associated with engineering staff time due to a greater volume of billable GI activities. An increase of $0.6 is associated with exit fees billed to a member that was terminated by the board due to non-payment of annual membership fees.

Each of the other miscellaneous revenue sources were also higher than expected in comparison to the budget.

The budget assumed the OVEC contract would be terminated after the first quarter. Earlier this year, SPP and OVEC reached an agreement for SPP to continue providing services until OVEC's transition to another provider was fully completed later in the year. This resulted in a favorable variance in Contract Services Revenue. New contract service fees for the administration of the Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP) were not assumed in the budget and also contribute to the favorable revenue variance.

Southwest Power Pool
2018 Financial Commentary
December 31, 2018
2018 Preliminary and Unaudited
(in thousands)

Expense

	2018 FY Actual	2018 FY Budget	Fav/(Unfav) Variance	
Salary & Benefits	$94,870	$96,056	$1,185	1.2%
Assessments & Fees	21,060	20,269	(791)	(3.9%)
Communications	3,840	4,474	634	14.2%
Maintenance	17,163	18,366	1,202	6.5%
Outside Services (Including RSC)	12,350	14,588	2,238	15.3%
Administrative	4,588	5,210	622	11.9%
Travel & Meetings	2,804	3,097	293	9.5%
Depreciation	18,053	19,390	1,338	6.9%
Other Expenses	9,217	9,302	85	0.9%
Total Expense	$183,945	$190,752	$6,806	3.6%

Salary & Benefits trail budget primarily due to a reduction in pension cost, which reflects actuarial valuations for both the retirement and retiree healthcare plans that were provided earlier in the year. Items partially offsetting the decrease in pension costs include retention payout for the RE staff and individually immaterial variances in various benefit accounts.

SPP received the annual assessment invoice from FERC in June. The revised estimate for FERC Assessments and Fees is reflected in the actual results, which is higher than the amount assumed in the budget.

The postponement of various initiatives (PMU data sharing, cloud storage solutions, and mobile device security) along with fewer than assumed circuits for membership growth has resulted in a favorable variance in communications expense.

The favorable variance in Maintenance is mainly driven by delays and/or deferrals of capital spending that drive incremental hardware and software maintenance. Additionally, spending for facilities related maintenance was favorable to budget due to shifts in timing of certain replacement/repair projects.

The overall favorable variance in Outside Services is driven by the following items: 1) increased utilization of engineering staff which reduces reliance on outside consultants for study activities, 2) various delays/reassessments of service engagements in IT, compliance, engineering, and operations, 3) decline in various assignments as the RE concluded its operations, and 4) various other immaterial variances across numerous departments.

Other expenses includes interest expense, capitalized interest, investment income, valuation adjustments, and various other income and expense amounts. Due to the unpredictability, the only amounts budgeted in this category are interest expense and capitalized interest. Interest expense is associated with debt issuances used for capital expenditures.

The valuation adjustments contribute to the overall favorable variance in other expenses and are not reflected in the net revenue requirement (NRR) recovery calculation since they are considered non-cash items. Exit fees billed to the terminated member were fully reserved, which created a $0.6 million variance that partially offsets the overall favorable variance in other expenses.

Southwest Power Pool
Monthly Financial Overview
December 31, 2018
2018 Preliminary and Unaudited
(in thousands)

	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Actual Jul-18	Actual Aug-18	Actual Sep-18	Actual Oct-18	Actual Nov-18	Actual Dec-18	FY 2018 Actual	FY 2018 Budget	Variance Fav/(Unfav)	FY 2017 Actual	Variance Fav/(Unfav)
Income																	
Tariff Administrative Service	$14,269	$12,483	$13,773	$13,570	$14,127	$13,539	$14,008	$14,124	$13,730	$13,966	$13,488	$13,892	$164,969	$164,001	$968	$162,847	$2,122
Fees & Assessments	2,565	2,795	2,456	2,301	2,176	2,570	2,210	2,619	2,099	1,777	1,647	1,676	26,892	26,093	799	27,496	(604)
Contract Services Revenue	44	44	44	44	44	47	46	54	276	58	97	56	856	156	701	533	323
Miscellaneous Income	492	417	395	420	584	387	480	458	369	559	879	747	6,187	3,963	2,224	5,745	443
Total Income	17,372	15,740	16,669	16,336	16,931	16,543	16,744	17,255	16,474	16,359	16,111	16,371	198,904	194,212	4,692	196,621	2,283
Expense																	
Salary	5,283	5,265	5,471	5,244	5,226	5,283	5,165	5,210	5,049	5,069	5,072	4,752	62,090	61,331	(759)	61,172	(918)
Benefits & Taxes	2,924	2,647	2,909	2,611	2,737	2,728	2,725	2,794	2,609	2,411	2,617	2,467	32,180	33,942	1,762	33,007	827
Continuing Education	44	46	58	28	87	18	46	78	24	45	53	72	600	783	182	471	(130)
Salary & Benefits	8,251	7,958	8,438	7,884	8,050	8,030	7,936	8,082	7,683	7,524	7,742	7,292	94,870	96,056	1,185	94,650	(221)
Employee Travel	127	171	151	198	196	159	129	194	126	190	151	103	1,895	2,168	273	2,023	128
Administrative	195	420	276	568	265	473	334	271	390	750	220	427	4,588	5,210	622	4,656	68
Assessments & Fees	1,689	1,689	1,689	1,689	1,689	2,022	1,765	1,765	1,765	1,765	1,765	1,765	21,060	20,269	(791)	21,663	603
Meetings	72	66	67	159	80	62	54	116	55	85	51	43	909	929	20	1,040	131
Communications	258	287	293	308	353	362	327	334	350	330	312	327	3,840	4,474	634	3,504	(337)
Maintenance	1,115	1,387	1,328	1,507	1,566	1,434	1,322	1,534	1,317	1,126	1,346	2,180	17,163	18,366	1,202	16,099	(1,065)
Services	826	1,224	792	877	998	828	1,081	1,299	1,020	1,111	818	1,296	12,172	14,257	2,086	12,417	246
Regional State Committee	8	25	13	11	21	9	11	18	17	12	21	12	178	331	152	202	24
Depreciation	1,831	1,691	1,354	1,551	1,460	1,396	1,396	1,588	1,425	1,555	1,448	1,356	18,053	19,390	1,338	27,716	9,664
Total Expense	14,372	14,918	14,404	14,751	14,677	14,775	14,357	15,201	14,148	14,450	13,876	14,801	174,729	181,450	6,721	183,971	9,242
Other Income/(Expense)																	
Investment Income	5	5	46	6	7	49	123	7	14	8	7	78	355	-	355	165	190
Interest Expense	(811)	(802)	(812)	(804)	(786)	(791)	(771)	(775)	(774)	(754)	(756)	(753)	(9,390)	(9,424)	35	(10,227)	837
Capitalized Interest	-	-	19	-	-	26	-	-	34	-	-	43	122	122	()	63	59
Change in Valuation of Swap	-	-	547	-	-	269	-	-	224	-	-	(309)	730	-	730	789	(59)
Other Income/Expense	165	(60)	10	35	71	87	38	75	28	(227)	(552)	(177)	(507)	-	(507)	(1,414)	908
Unrealized Gain on Investment	512	(355)	(261)	13	218	9	334	323	(5)	(682)	192	(826)	(528)	-	(528)	1,499	(2,027)
Chg in Emp Benefit Plan Funded Status	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6,434	(6,434)
Net Other Income (Expense)	(129)	(1,212)	(452)	(749)	(491)	(351)	(275)	(370)	(478)	(1,655)	(1,109)	(1,945)	(9,217)	(9,302)	85	(2,691)	(6,526)
Net Income (Loss)	$2,871	($391)	$1,814	$835	$1,763	$1,418	$2,112	$1,684	$1,848	$255	$1,126	($376)	$14,959	$3,460	$11,498	$9,959	$4,999
2018 Headcount																	
Approved Budgeted Positions	619	619	620	620	621	621	609	609	609	609	609	609	609	609		610	
Actual Headcount (Incl. Vacancy)	601	603	601	598	594	596	592	589	593	595	593	589	589			595	
Actual Positions (Excl. Vacancy)	620	619	614	612	613	618	611	611	609	606	608	609	609			615	
Approved Positions Over / (Under)	1	-	(6)	(8)	(8)	(3)	2	2	-	(3)	(1)	-	-				
Headcount Vacancy Run rate	3%	3%	2%	2%	3%	4%	3%	4%	3%	2%	2%	3%	3%	3%			
NRR Over / (Under) Recovery	$4,526	$998	($2,402)	$2,430	$2,560	($2,556)	$2,786	$1,964	($2,595)	$2,724	$2,557	($2,789)	$12,816			$3,288	

Southwest Power Pool
Current Month Financial Overview
December 31, 2018
2018 Preliminary and Unaudited
(in thousands)

	Current Month Compared to Forecast			YTD Actual Compared to YTD Budget			FY Actual Compared to FY Budget		
	Dec-2018 Actual	Dec-2018 Forecast	Variance Fav/(Unfav)	Dec-2018 Actual	Dec-2018 Budget	Variance Fav/(Unfav)	FY 2018 Actual	FY 2018 Budget	Variance Fav/(Unfav)
Income									
Tariff Administrative Service	$13,892	$13,990	($98)	$164,969	$164,001	$968	$164,969	$164,001	$968
Fees & Assessments	1,676	1,881	(205)	26,892	26,093	799	26,892	26,093	799
Contract Services Revenue	56	53	3	856	156	701	856	156	701
Miscellaneous Income	747	501	245	6,187	3,963	2,224	6,187	3,963	2,224
Total Income	16,371	16,426	(55)	198,904	194,212	4,692	198,904	194,212	4,692
Expense									
Salary & Benefits	7,292	8,003	711	94,870	96,056	1,185	94,870	96,056	1,185
Employee Travel	103	149	46	1,895	2,168	273	1,895	2,168	273
Administrative	427	380	(47)	4,588	5,210	622	4,588	5,210	622
Assessments & Fees	1,765	1,765	-	21,060	20,269	(791)	21,060	20,269	(791)
Meetings	43	52	9	909	929	20	909	929	20
Communications	327	330	4	3,840	4,474	634	3,840	4,474	634
Maintenance	2,180	2,226	46	17,163	18,366	1,202	17,163	18,366	1,202
Services	1,296	1,378	82	12,172	14,257	2,086	12,172	14,257	2,086
Regional State Committee	12	15	3	178	331	152	178	331	152
Depreciation	1,356	1,500	144	18,053	19,390	1,338	18,053	19,390	1,338
Total Expense	14,801	15,799	998	174,729	181,450	6,721	174,729	181,450	6,721
Other Income/(Expense)									
Investment Income	78	-	78	355	-	355	355	-	355
Interest Expense	(753)	(752)	(1)	(9,390)	(9,424)	35	(9,390)	(9,424)	35
Capitalized Interest	43	43		122	122	()	122	122	()
Change in Valuation of Swap	(309)	-	(309)	730	-	730	730	-	730
Other Income/Expense	(177)	-	(177)	(507)	-	(507)	(507)	-	(507)
Unrealized Gain on Investment	(826)	-	(826)	(528)	-	(528)	(528)	-	(528)
Net Other Income (Expense)	(1,945)	(710)	(1,235)	(9,217)	(9,302)	85	(9,217)	(9,302)	85
Net Income (Loss)	($376)	($83)	($293)	$14,959	$3,460	$11,498	$14,959	$3,460	$11,498
Headcount	589	595	(6)	589	609	(20)	609	609	-

Southwest Power Pool
Balance Sheet
December 31, 2018
2018 Preliminary and Unaudited
(in thousands)

	12/31/2018	12/31/2017	Net Change
ASSETS			
Current Assets			
Cash & Equivalents	$93,902	$100,496	($6,594)
Restricted Cash Deposits	344,590	340,612	3,978
Accounts Receivable (net)	34,454	74,391	(39,937)
Other Current Assets	16,728	8,539	8,190
Total Current Assets	$489,674	$524,038	(34,364)
Total Fixed Assets	77,254	79,774	(2,520)
Total Other Assets	2,628	5,499	(2,871)
Investments	25,239	24,456	782
Total Assets	$594,795	$633,767	($38,972)
LIABILITIES & EQUITY			
Liabilities			
Current Liabilities			
Accounts Payable (net)	$51,401	$75,844	(24,442)
Customer Deposits	344,898	340,612	4,286
Current Maturities of LT Debt	23,497	23,359	138
Other Current Liabilities	90,812	98,801	(7,989)
Deferred Revenue	187	3,928	(3,741)
Total Current Liabilities	511,135	542,544	(31,409)
Long Term Liabilities			
Long-Term Debt	192,241	213,677	(21,436)
Capital Lease Obligation	()	1,966	(1,966)
Other Long Term Liabilities	33,182	32,301	881
Total Long Term Liabilities	225,423	247,944	(22,521)
Net Income	14,959	9,959	4,999
Members' Equity	(156,721)	(166,680)	9,959
Total Members' Equity	(141,762)	(156,721)	14,959
TOTAL LIABILITIES & EQUITY	$594,795	$633,767	(38,972)

Southwest Power Pool
Headcount Analysis
December 31, 2018

	Current Month Actual vs. Budget			Year End Actual vs. Budget		
	Actual Dec-18	Budget Dec-18	Over/(Under) Budget	2018 Actual	2018 Budget	Over/(Under) Budget
Information Technology	161	164	(3)	167	164	3
Operations	159	162	(3)	162	162	0
Engineering	78	80	(2)	85	80	5
Process Integrity	57	54	3	58	54	4
Administration	49	49	0	49	49	0
Corporate Services	30	30	0	30	30	0
Regulatory Policy & General Counsel	25	27	(2)	27	27	0
Market Monitoring	15	16	(1)	16	16	0
Market Design	6	6	0	6	6	0
Interregional Relations	1	3	(2)	1	3	(2)
Communications & Gov't Affairs	8	7	1	8	7	1
SPP Regional Entity	0	11	(11)	0	11	(11)
Total Positions	589	609	(20)	609	609	0
Vacancy Estimate				(20)	(18)	4
Headcount Including Vacancy Est.				589	591	4

Headcount changes *	
2018 Beginning Positions (598 RTO / 23 RE)	621
RE resignations / retirements	(9)
RE staff filling open RTO positions	(7)
Operations positions eliminated	(3)
Out-of-budget positions added (Eng)	3
Out-of-budget position added (IT)	1
RC West positions	3
Total RTO Actual	609

RE Staffing Changes	
RE Beginning budgeted positions	23
Transfers to RTO open positions	(7)
Resignations	(9)
Total positions transferred to RTO	7

* Beginning positions were 621 with the assumption 12 RE staff would leave SPP and result in a year-end budget of 609 positions. The number of positions retained from the RE was 7, resulting in an RTO forecast of 605 compared to 609 prior to any other staffing changes. In addition, 3 operations positions were eliminated, 4 out-of-budget positions were added in IT and engineering, and 3 of the 20 RC West positions were added in Q4 2018 (the RC West positions are reflected in the operations division).

Notes on RE staffing: The 2018 budget assumed the RE would be dissolved by June 30, 2018, and SPP would retain 11 of the 23 staff members (i.e. 12 staff would voluntarily leave). This assumption was for budgeting purposes only and did not negate the possibility of retaining all 23 staff members if necessary, as SPP committed to the continued employment for all remaining RE staff. The total number of RE staff absorbed by the RTO was 7, which is 4 less than the budget assumption of 11. Of the 7 positions transferring to the RTO, 5 new positions were added to augment compliance and interregional affairs functions, 1 was placed in Human Resources, and 1 was placed in Communications. In addition, 7 RE staff transferred to fill open requisitions within the RTO.

As of August 31st, the RE was dissolved with no remaining staff associated with the RE.

Southwest Power Pool, Inc. - Finance Committee Project Dashboard

1 - Reliability Assurance	2 - Maintain An Economical, Optimized Transmission System	3 - Enhance and Optimize Interdependent Systems	4 - Enhance Member Value and Affordability

Project Name ----------------- Linkage to Strategic Plan	Project Description	SPP Owning Officer	Approved Budget --------------- Est. Cost at Completion	Remaining Milestones	Comments
ACTIVE PROJECTS					
Identity and Access Management Phase 2 -------------- 1	Automation of identity and access system to ensure CIP Compliance	Sugg	$0.5M ------------------ $0.5M	Re-baselining in progress, with focus on certification; milestone dates TBD	Spend to date: $0.4M.
Online TSAT ---------------------- 1	Transient Stability Assessment Tool (TSAT) will be used to ensure power transfers do not cause a voltage collapse event or blackout.	Rew	$1.4M ------------------ $0.7M	Test - 3/1/19 Training – 3/1/19 Implementation – TBD Close – TBD	Under budget from software and hardware savings from original estimates. Production date to be reset due to architect redesign from vendor.
TTSE DTS Upgrade Project - Phase 3 ---------------------- 1	Enhancement to the current DTS to incorporate virtualization tools mimicking those available in the control center.	Rew	$0.1M ------------------ $0.1M	Build - 9/29/18 Test - 11/30/18	This project has completed the execution phase as of December 2018. Zero capital dollars were spent.
Settlements Replacement ---------------------- 1	Replacement of the current Market and Transmission Settlement Systems with a custom designed single high performance scalable system solution.	Dunn	$5.3M ------------------ $5.3M	Build – 10/31/18 Test – 3/29/19 Implementation – 5/1/19	Project in Yellow status due to risk to interim milestones. Project on budget.
ITSM Tool Upgrade ---------------------- 1	**Phase 1** - Remedy Upgrade (Incident, Problem, Change, Asset, etc.) Current Remedy Version is at end of life for Vendor support. **Phase 2** - Implement Upgrade of BPPM -Performance Manager (monitoring software)	Sugg	$1.0M ------------------ $0.6M	**Phase 1** Build - 09/14/18 Training - 01/18/19 Implementation - 01/21/19 **Phase 2** Build - 3/13/2019 Test - 03/15/2019 Cutover 04/04/2019	Phase 1 is in progress and will implement Remedy upgrade in January. Phase 2 has signed SOW from vendor and will begin execution in January.
Reliability Communication Tool ---------------------- 1	Project would create an application to facilitate the systematic issuance, receipt, and auditable documentation of operating instructions.	Rew	$0.0M ------------------ $0.0M	New architecture installation - 2/8/19 Testing (internal only) - 3/1/19 Implementation - 4/5/19	Decision was made to use internal staff for the development; therefore, no capital expenditures. Project was delayed about five weeks due to new architecture being needed for optimal security and compliance. As a result, implementation date shifted from 2/27/19 to 4/5/19.

Southwest Power Pool, Inc. - Finance Committee Project Dashboard

1 - Reliability Assurance	2 - Maintain An Economical, Optimized Transmission System	3 - Enhance and Optimize Interdependent Systems	4 - Enhance Member Value and Affordability

Project Name ------------------ Linkage to Strategic Plan	Project Description	SPP Owning Officer	Approved Budget ---------------- Est. Cost at Completion	Remaining Milestones	Comments
FERC Order 841 ---------------------- 3	The Federal Energy Regulatory Commission (FERC) amended its regulations under the Federal Power Act via the FERC Order 841 Final Rule to remove barriers to participation of electric storage resources in the capacity, energy, and ancillary service markets operated by RTOs and ISOs. In response to the Order, SPP will adhere to mandated FERC deadlines to file tariff changes needed to implement the requirements of this Final Rule to establish a participation model consisting of market rules that facilitate electric storage resources (ESR) participation in the Marketplace. SPP will also take the necessary actions of updating the modeling and dispatch software to implement the tariff provisions.	Rew	$0.4M ------------------- $0.4M		Requirements gathering and documentation in progress.

Southwest Power Pool, Inc. - Finance Committee Project Dashboard

1 - Reliability Assurance	2 - Maintain An Economical, Optimized Transmission System	3 - Enhance and Optimize Interdependent Systems	4 - Enhance Member Value and Affordability

Project Name ----------------- Linkage to Strategic Plan	Project Description	SPP Owning Officer	Approved Budget --------------- Est. Cost at Completion	Remaining Milestones	Comments
DEFERRED, CONTINGENT OR DECLINED PROJECTS					
Distributed Generation Functionality	Enhancement to SPP's markets to allow participation by distributed generation resources and storage devices.	Rew	Deferred Project: Budget Not Approved	TBD	Not Started. ------------------------------- FERC has determined that more information is needed before taking action. This ruling has been deferred and a technical conference has been scheduled for early April.
Freeze Date Replacement	The project will update the process that calculates firm rights used in real time congestion processes in accordance with new rules and requirements agreed upon by CMP (SPP, MISO, PJM, TVA, AECI, MHEB, LGEE) members.	Rew	Deferred Project: Budget Not Approved	TBD	Not Started.
Completed Projects					
The Circuit Redesign --------------------- 4	Update to SPP's employee intranet: improved functionality, enhanced ability to find information, and an improved design to drive greater employee collaboration.	Ross	$0.2M ------------------ $0.3M	Closed – 6/30/18	The Circuit went live 5/31/18. This project is complete.
GRC Tool Project --------------------- 1	Implementation of a governance, risk, and compliance (GRC) system.	Desselle	$1M ------------------ $0.3M	Closeout - 02/17/18	This project is complete.
Engineering Hub --------------------- 3	Development of an internal web-based front end that provides engineering data review and editing capability.	Nickell	$0.8M ------------------ $0.5M	Closed – 1/19/18	This project is complete.

Status	Project Phase	Impacting/Facing
Green	PREP	Yes - Facing
Yellow	Initiating	Yes - Impacting
Red	Planning	No
	Executing	
	Closing	

Capital Spending Review
December 31, 2018

Prepared by: Accounting Department

Southwest Power Pool

Project and Foundation Investments as of December 31, 2018

Note: Dollar amounts presented in the tables throughout the report are in $000s

Projects	Budget*	Forecast*	Variance
Settlement Systems Replacement**	$ 5,291	$ 5,291	$ -
Training and Testing Simulated Environment (TTSE)**	2,455	2,504	(49)
Voltage Security Assessment Tool (VSAT) (Complete)	1,438	967	471
Transient Stability Tool (TSAT)	1,415	663	752
IT Service Management Tool Upgrade	1,048	564	484
Identity and Access Management (IAM)	479	503	(24)
Data Lake Phase**	350	350	-
Project Management Tool Replacement**	498	498	-
Circuit Redesign (Complete)	163	248	(85)
Replicated Data Server Upgrade (Complete)	-	46	(46)
Total Projects	**$ 13,137**	**$ 11,634**	**$ 1,503**
Foundation - 2018 * **	**Budget**	**Actual (Preliminary)**	**Variance**
Information Technology	$ 8,100	$ 7,210	$ 890
IT - Other Departments	1,206	597	609
Operations	2,414	2,398	16
Settlements	250	-	250
Facilities	216	217	(1)
Total Foundation - 2018	**$ 12,186**	**$ 10,422**	**$ 1,765**

** Budget amounts are per the 2018 capital projects budget approved by the board unless otherwise noted. Forecast includes capital spending only.*

*** Budget updated to reflect amount approved in 2019-2021 budget cycle.*

**** Foundation projects are reforecast annually. Unused funds do not carry over to the following year.*

Multi-Year Capital Projects Over $1 Million

Settlement Systems Replacement

- The project began in April 2017 and the first milestone was completed in July 2017 with the successful delivery and implementation of the formula builder.
- Development of the settlement calculations within the formula builder began with Milestone 2 and ran through Milestone 4 which ended October 31, 2018.
- Milestone 2 (core calculation engine development – the largest of all five milestones) concluded with the delivery of the core calculation engine in March 2018.

Key Completion Dates
Build: 10/2018
Testing: 4/2019
Implementation: 5/2019

- Milestone 3 was completed in June 2018 which included the user interface functionality required to support day-to-day settlement operations.
- Milestone 4 was focused on all remaining development items, in addition to workflow and audit processes of the new system, and officially concluded on October 31, 2018. However, there remains system defects and unfinished functionality that the vendor is continuing to work on which resulted in delays in the deliverables and progress of the project. The project team has taken steps to address the ongoing issues by re-aligning priorities and resources.
- Milestone 5 includes internal testing and defect fixes, along with transition of system support from the vendor to internal staff. Member connectivity testing began on January 9th and member unstructured testing is currently planned to start at the end of January. However due to ongoing issues with system performance, accuracy, and functionality, the transition from vendor to internal staff has been postponed. An additional statement of work is currently being negotiated with the vendor to address system issues and to ensure the original go-live date of May 1st is met. The cost for this additional work is not yet finalized and is not included in the forecast amount shown below.

	Budget	2017	2018	2019	Total Forecast	Variance
Capital Expense	$ 5,291 *	$ 1,967	$ 3,119	$ 205	$ 5,291	$ 0
Operating Expense (Inception Workshop)	$ -	$ 26	$ -	$ -	$ 26	$ (26)

* *Original budget for the project as approved in the 2017 budget was $5.1M.*

Training and Testing Simulated Environment (TTSE)

- Phase 1 which included expanding the Maumelle training facilities, enhancing the dispatcher training simulator (DTS), and creating an operations-dedicated DTS environment was completed in 2016 at a cost of $0.2M.
- Phase 2 involves the addition of a stand-alone interactive market simulator and contains two components:
  - Phase 2A: Assembly of market simulation hardware and environment. Higher priority assignments had initially impeded the progress on this phase. However, IT staff was able to complete the work necessary to close out this phase during 3Q'18.
  - Phase 2B: Build and integrate market simulation software. This phase was approved in the 2019-2021 budget cycle at a cost of $2.2M. An impact assessment was completed by the vendor in February 2018 that was utilized for the 2019 budget cycle which resulted in a $0.7M decrease from earlier estimates. A statement of work is expected from the vendor in January 2019 and the work on the project is planned to commence in February 2019.

<u>Phase 2B</u>
<u>Key Completion Dates</u>

TBD upon completion of requirements and design

- Phase 3 included the addition of visualization tools mimicking the screens available in the control center and was performed entirely by internal staff. Testing and implementation of the tools were completed during 4Q'18.

	Budget*	2016 2017	2018	2019	Total Forecast	Variance
Capital Expense	2,455	$ 228	$ 89	$ 2,187	$ 2,504	$ (49)

** Budget updated to reflect amount approved in 2019-2021 budget cycle.*

Voltage Security Assessment Tool (VSAT)

- This project was on a two-phase schedule to implement the real-time mode first, followed by look-ahead and study modes.
- Activities in 2017 included the installation of VSAT software and hardware, testing and training on the tool and validation of data in the QA environment.
- Installation of the real-time mode in the Electronic Security Perimeter (ESP) was completed in 2Q'18. Implementation of study and look-ahead modes occurred in 3Q'18.
- The original project budget assumed certain hardware and software costs that were ultimately covered by IT Foundation, resulting in an overall favorable variance to budget.

	Budget	2016 2017	2018	Total Actual	Variance
Capital Expense	$ 1,438	$ 924	$ 43	$ 967	$ 471

Transient Security Assessment Tool (TSAT)

- After the successful completion of VSAT (real-time mode) in 2Q'18, the TSAT project was launched.
- In May 2018, the vendor began making enhancements to the existing Market Operating System (MOS) and Energy Management System (EMS) that were required prior to the build and implementation of the TSAT software. The enhancements were completed in June 2018 and released to SPP for testing.

Key Completion Dates
Build: 12/2018
Testing: 5/2019
Implementation: 5/2019

- During 3Q'18, the TSAT software vendor began working on software installation and scenario development. The software was installed in the development environment in 4Q'18 during which the project team determined that there was a need to redesign the architecture of the core processors for the application. The project schedule has been adjusted six weeks to allow time for redesign. The cost of the project is not affected by the required changes.

- Factors contributing to the favorable variance include: cost savings from bundling a very large hardware order, use of virtual hardware where possible, and negotiated savings with the software vendor.

	Budget	2018	2019	Total Forecast	Variance
Capital Expense	$ 1,415	$ 543	$ 120	$ 663	$ 752

IT Service Management Tool Upgrade

This project is comprised of two phases:

- Phase 1: Existing IT service management tool, Remedy, reached end of life for vendor support and the decision was made during 2Q'18 to upgrade to the latest version. The decision to upgrade versus purchasing a new tool resulted in savings which accounts for the favorable variance to budget.
- In 3Q'18, re-baselining of the project became necessary due to internal resource constraints resulting in the implementation date being moved from November to January.

Key Completion Dates
Phase 1
Build: 10/2018
Training: 1/2019
Implementation: 1/2019
Phase 2
Build: 3/2019
Implementation: 4/2019

- The environment build was completed in 4Q'18. Internal training and implementation of the tool is on schedule in January 2019 which will complete Phase 1.
- Phase 2: This phase consists of the implementation of an IT environment performance management and monitoring solution. Phase 2 had dependency for the Remedy upgrade to be in production before the implementation could be completed.
- The software for this phase was purchased at the end of the 4Q'18. During 1Q'19, the build and installation of the software will be completed by internal resources, after which the vendor will configure the applications to provide a functional monitoring solution.

	Budget	2018	2019	Total Forecast	Variance
Capital Expense	$ 1,048	$ 376	$ 188	$ 564	$ 484

Capital Projects Less Than $1 Million

	Budget	2017	2018	2019	Forecast	Variance
Identity and Access Management (IAM)	$ 479	$ 111	$ 392	$ -	$ 503	$ (24)
Circuit Redesign (Complete)	$ 163	$ 231	$ 17	$ -	$ 248	$ (85)
Data Lake Phase 3*	$ 350	$ -	$ -	$ 350	$ 350	$ -
Project Management Tool Replacement*	$ 498	$ -	$ -	$ 498	$ 498	$ -
Replicated Data Server Upgrade (Complete)	$ -	$ -	$ 46	$ -	$ 46	$ (46)

** Budget updated to reflect amount approved in 2019-2021 budget cycle.*

Identity and Access Management (IAM)

- Phase 1 of this project, consisting of requirements gathering and the purchase of the software solution, was completed in 2017.
- Phase 2 was for implementation of the solution with consulting and development services to be provided by an outside vendor. Delays due to resource constraints, conflicting organizational priorities and vendor/tool issues resulted in a need to re-baseline the project.
- Following recommendations from a third-party review and critical infrastructure protection (CIP) audit findings, staff decided to shift focus to enabling access certification through development of an access management inventory as the foundational component of a successful IAM practice. Once this foundation is in place, staff will revisit implementation of the software solution as the system supporting the IAM process.
- Milestone and go-live dates will be determined in 1Q’19 as part of the project re-baseline effort.

Circuit Redesign

The new Circuit was launched earlier in 2018. Staff was given access to the site on May 31st.

Data Lake Phase 3

There was no capital spend in 2018 and the direction of the project is being reevaluated. A determination on the direction of the project is expected in 2Q'19. The project was approved in the 2019-2021 budget at a cost of $0.4M.

Project Management Tool Replacement

Project is targeted to be completed in two phases. Phase 1, which included discovery and analysis, was completed in early 4Q'18 and a software vendor was selected by staff as a result. Phase 2 of the project (purchase of software and implementation) was approved in the 2019-2021 budget cycle for $0.5M. Phase 2 has not yet commenced, pending further review and approval by the Project Review Prioritization Committee (PRPC).

Replicated Data Server Upgrade

During the 2018 budget cycle, this project was considered to be contingent upon the MWTG decision to participate in SPP; therefore, no funds were allocated to this project in the 2018 budget (listed as a "deferred" project at a cost of $210k). The Operations Reliability Working Group (ORWG) later chose to pursue the project for existing SPP members. In 3Q'18, the project was approved to move forward at an out-of-budget cost of $.05M. Requirements gathering and design phases of the project were completed in 3Q'18. The upgrade was put into production on schedule at a cost of $.04M during 4Q'18.

Deferred Projects

The following are the projects that were flagged as “deferred/contingent” in the 2018 budget and no budget funds were allocated due to uncertainty about regulatory requirements, timelines, solution, etc. The amounts shown below are the cost estimates per the 2018 budget document.

	Projected cost per 2018 Budget
Distributed Generation Functionality	$ 200
Freeze Date Replacement	$ 200
Replicated Data Server Upgrade*	$ 210

** Project status explained in previous selection.*

Distributed Generation Functionality

FERC has issued a notice of proposed rulemaking regarding this functionality and a final order detailing the requirements for compliance was issued in February with an implementation deadline of December 2019. This functionality will require enhancements to the markets system to allow participation by distributed generation resources and storage devices. This project was approved in the 2019-2021 budget cycle as “FERC Order 841 – Electric Storage” with a budgeted cost of $0.4M.

Freeze Date Replacement

The project will update the process that calculates firm rights used in real-time congestion processes in accordance with new rules and requirements agreed upon by CMP (SPP, MISO, PJM, TVA, AECI, MHEB, LGEE) members. This project was forecast in the 2019-2021 budget cycle for $0.3M to begin in 2020.

Foundation Capital Expenditures

The following sections discuss foundational capital expenditures for information technology, operations, settlements, and facilities for the current year. Although foundational spend is presented for the upcoming three years during each annual budget cycle, foundational budgets are re-forecast every budget cycle for the upcoming year. The table shows the 2018 foundation budgets and updated amounts for 2019 and 2020 as approved in 2019-2021 budget cycle.

	2018	2019	2020	Total
Information Technology	$ 8,100	$ 8,200	$ 8,400	$ 24,700
IT - Other Departments	$ 1,206	$ 840	$ 1,740	$ 3,786
Total IT Foundation	*$ 9,306*	*$ 9,040*	*$ 10,140*	*$ 28,486*
Operations	$ 2,414	$ 2,559	$ 2,264	$ 7,237
Settlements	$ 250	$ 235	$ -	$ 485
Facilities	$ 216	$ 965	$ 285	$ 1,466
Total	**$ 12,186**	**$ 12,799**	**$ 12,689**	**$ 37,674**

Foundation Expenditures: Information Technology

The budget for IT Foundation for 2018 was $8.1M, which is relatively flat compared to the 2017 budget of $7.9M. The IT Foundation budget captures corporate-wide hardware and software requirements to support SPP's business applications and systems and is managed in two broad categories:

- **Infrastructure Refresh:** This category includes upgrades and/or replacements of existing infrastructure to support the ongoing requirements of existing systems and services.
- **New Initiatives:** This category is for incremental hardware, software, and/or development services to support new IT and/or Corporate projects and services.

IT Foundation (excludes non-IT)	2018 Forecast as of 9/30/18	2018 Budget	2018 Actual (Preliminary)	Budget vs. Actual Variance
Infrastructure Refresh	$ 6,851	$ 6,337	$ 6,952	$ (615)
New Initiatives	$ 1,815	$ 1,763	$ 258	$ 1,505
Total	**$ 8,666**	**$ 8,100**	**$ 7,210**	**$ 890**

2018 actual of $7.2M includes $450k of spend requisitioned in late-2017 that was received/recorded as capex in early 2018.

The total spend during 4Q'18 was $3.1M and included the following items:

- Replacement of aged storage switches at each data center that support SPP Storage Area Network (SAN) infrastructure ($1.1M) – *Infrastructure Refresh*
- Replacement of firewall hardware that is reaching end-of-life ($1.1M) - *Infrastructure Refresh*
- Software licenses to monitor servers and applications ($0.2M) - *Infrastructure Refresh*
- Additional storage to meet the needs of SPP's data retention and long-term archival policies ($0.2M) - *Infrastructure Refresh*
- Replacement of aged servers, routers and appliances that support infrastructure ($0.2M) – *Infrastructure Refresh*
- Software licenses for automation/productivity, cabling, cabinets ($0.1M) – *New Initiatives*

Aside from the IT Foundation budget, a separate budget of $1.2M exists to support capital requirements for approximately 12 departments (Engineering, H/R, Legal, etc.). Total spend during 4Q'18 was $0.2M and included the following items:

- Software licenses for Engineering that specializes in mathematical computing which supports data analysis and simulation (<$.01M)
- Software suite of tools for Engineering which allows the user to switch between data visualization, system simulation and results analysis ($0.1M)
- Additional servers (2) for Engineering Operational and Planning group which will aid and enhance the numerous studies on reliability and efficiency of the Bulk Electric System (<$.01M)

IT - Other Departments	2018 Forecast as of 9/30/18	2018 Budget	2018 Actual (Preliminary)	Budget vs. Actual Variance
Infrastructure Refresh	$ 779	$ 1,206	$ 597	$ 609

Foundation Expenditures: Operations, Facilities & Settlements

The following foundation budgets reflect capital spend for enhancements to operations, marketplace, and settlements systems, and for various upgrades/improvements to SPP's physical facilities.

Other Foundation	2018 Forecast as of 9/30/18	2018 Budget	2018 Actual (Preliminary)	Budget vs. Actual Variance
Operations - MOS Enhancements	$ 2,000	$ 2,000	$ 2,047	$ (47)
Operations - Legacy Systems	$ 367	$ 414	$ 351	$ 63
Settlements	$ -	$ 250	$ -	$ 250
Facilities	$ 335	$ 216	$ 217	$ (1)

<u>Operations Marketplace Enhancements</u>

Total spend during 4Q'18 was $0.5M and included the following items:

- Functionality tested and implementation of R231 – Mitigation of Locally Committed Resources.
- Functionality tested and implementation of RR252 – Out of Merit Energy (OOME) Enhancement.
- Functionality tested and implementation of RR253 – Dispatchable Variable Energy Resources (DVER) Regulation Enhancement.
- Work began on Market Release 1.27 which includes:
    - Multiple Market User Interface (MUI) enhancements
    - Delivery of RR210 Contingency Reserve Deployment (CRD) Test Support (to be member-tested with Settlement Systems Replacement Project)
    - Changes for RR266 – JOU Combined Single Resource Modeling Post Settlement Share Allocation

<u>Operations Legacy System Enhancements</u> include energy management system (EMS), control-room operations window (CROW), open access same-time information system (OASIS), dispatch training simulator (DTS), centralized modeling tool (CMT) and various other applications supporting the operations division. The total spend in 4Q'18 was $0.2M which included updates to the CMT and EMS system.

<u>Settlements Enhancements</u> – There were no enhancements to the existing system in 2018 due to ongoing work to develop a new settlement system.

Unbudgeted Report
2018

PO Number	Project Name	Vendor Name	Scope of Work/Item Description	Total Amount	Budgeted	Unbudgeted	Notes
PO2018-1274	2018 Foundation General	Burns and McDonnell	WO #19- 2019 ITP Study	$180,000	-	$180,000	(A)
PO2018-1530	RC West Implementation	CDW Direct, LLC	Servers, Licenses, HW/SW Support for OSIsoft PI System	$154,504	-	$154,504	(B)
PO2018-1665	2018 Foundation General	Aneden	Aneden Consulting MSA WO 5 Studies for compliance with NERC MOD-033-1	$214,673	-	$214,673	
PO2018-1577	2018 IT Foundation	Alstom	Alstom IM Custom SW MNT-Addendum # 1	$199,920	-	$199,920	(C)
				$749,097	-	**$749,097**	

(A) While the cost of this service was not covered in the 2018 budget, there was offsetting revenue estimated at $172k. Therefore, the anticipated net impact of this out of budget item was approximately $8k.

(B) This hardware was included in the original RC West project estimates and was within the proposed project budget for both the capital and operating components. At the time this purchase was made, the project budget had been approved by the SPP Finance Committee, but had not yet been presented to the board (Dec 2018). Therefore, this purchase was submitted as an “out-of-budget” request.

(C) SPP budgeted a total of $1.9MM across 2017-2018 for Market maintenance and support. In 4Q 2018, it was determined that an additional $199k was needed to cover remaining 2018 work.