NOV. 7 QBR TRANSCRIPT

Due to trouble with the recording and poor audio quality, we are unable to share the audio. The transcript starts during Administrator Elliot Mainzer's review of BPA's safety target. Prior to this Director of Communications Scott Simms had provided an introduction and Mainzer discussed the 2018 Regional Roadshow.

SLIDE 5 – SAFETY

Elliot Mainzer:…leading indicators. We consider those to be quite important indicators on progress on our safety culture and clearly feeling comfortable in speaking up if they see concerns. And this year we also monitored our days ahead restricted transfer indicator – our DART scores – and we actually had our lowest recorded DART scores since the 1970s when we began reporting this. So the severity of injuries at Bonneville have been coming down and we are making good progress on improving safety reporting. But this like everything else is an area where we just have to keep our eye on the ball and keep focusing and never let up. We have work to do and we hope this next year to see all of our indicators, especially our IFR rate, within target.

SLIDE 6 – BENDING THE COST CURVE

I'm then going to turn to the next slide, this of course outside of safety, this really has been in many ways the central focus of the last four to five years as my time as administrator something that my entire leadership team and management team and really recently I can say all of the people at Bonneville are really focused on and this is bending our cost curve.

I think all of you on the phone today I am sure are familiar with the controversy of this conversation – the concerns about the rising rates at BPA and our programmatic costs. It was probably one of the very first things brought to my attention. It's really strongly in public power and others have spoken and I think with a really strong voice and we really have tried over the past couple of years to get this rate escalation and programmatic costs under control.

You can see going back to 2008/2010 we were at 26 percent rate period on rate period increase in IPR costs; 13 percent the following rate period; and in BP-14 another 4 percent. The first couple years in BP-16 and BP-18 we were able to really start nibbling at the inflation and the entire enterprise programmatic reduction.

And finally going into the BP-20 rate period we finally have been able to knock all the inflation out of our programmatic costs and offer an actual 4 percent reduction in total

Integrated Program Review costs rate period on rate period. I think that is the first time we have done that in a very long time.

Just two things. First of all it's very important for me to just acknowledge this incredible hard work so many people across BPA who I think have tried to respond to the concerns articulated by our customers. This really goes down to the heart of our business every single individual feels this one way or another. My managers, our leadership team, this is just something that we recognize. Not only are we hopefully turning the corner a little bit but we need to keep going, got to keep doing this indefinitely. This has to be part and parcel of how we are managing the federal system and our assets and of course our relationships with our other business partners. It's just very important for me as administrator for our customers to see their feedback and their input being reflected in our actual business performance. So um we will keep going, no rest for the weary but at least we are starting to see specific tangible measurable results from all the cost management efforts at BPA.

SLIDE 7 – BP-20 PROPOSED POWER RATES

I want to turn your attention to more detailed look at what we are facing for the BP-20 proposed power rates because quite frankly we're not out of the woods and this is still not the story we want to be getting to over time. We still are facing some significant upward rate pressure from a number of variables many of them on the revenue side which now is going to be increasingly central focus of what we are doing in the years ahead. We know we are not going to be able to cost manage our way to competiveness. We really do need to grow the markets for power and low cost way. Here is exactly where we are for power rates.

This graphic is quite instructive. If you look to the left hand side of the graph that stack of boxes on the left side shows you the specific drivers that are placing upward rate pressure for BP-20. The first one, the black box at the bottom, is $61 million. That is the cost and consequences of the decision we made a few years ago to no longer capitalize our energy efficiency program. The first couple years, the last couple of years, some of this was masked by savings from Regional Cooperation Debt. We're now having really to face the consequences of this. It is a real impact at $61 million.

The next block above reflects the continued hits we have been taking a combination of lower gas prices, wholesale markets and a bit of load loss embedded in there as well. It has been a tough market. We tried to run the ticker back a bit this year. I think many of you are familiar with the Portland General [Electric] transaction we executed. We've been selling some capacity and participating actively in the ancillary services auctions but now of course looking more long-term of course our long-term hedging program and really trying to revisit all of our long-term inventory risk curves. But at the end of the day we are still struggling like other hydro suppliers with tough secondary market so that's a $75 million impact.

On top of that we've got a $24 million hit from DSI sales and on top of that another $30 million in load lost. This is a phenomenon that we are facing in a number of areas of our service territory. Our customers have experienced some significant flattening of loads in certain areas. That of course ends up hitting right to our bottom line in the form of lower PF sales and more energy sold into alternative markets.

On top of the $30 million is the $10 million cost of some additional dollars we are intending to put back in the bank according to our Financial Reserves Policy to help support our days cash on hand target for Power. We have been struggling again to try to keep those balances in healthy condition. I appreciate the feedback. We were initially thinking we might need to go to $20 million to top it off at $40 [million] based off last rate period's decision. Customers pushed back pretty hard on that one and we thought $10 [million] was a reasonable compromise at the end of the day. I just feel a tremendous responsibility as administrator to manage the liquidity and days cash of the business and that of course has a consequence of upward rate pressure. And just a number of other miscellaneous items on top of that.

So you can see just walking into the rate case, [2012] Residential Exchange [Settlement] escalation, we face pretty significant headwind of upward rate pressure and what we have tried to do is just systematically find a way to get the rate increase down to a significantly lower level. We started – as you move across this graphic starting with the green boxes – the first is we are going to be removing the spill surcharge in BP-20. That will just get absorbed as part of our secondary portfolio and with some additional cost-management actions in our fish and wildlife portfolio.

We have taken a significant look at our long-term financial models. We have looked at our repayment studies and found some savings there. We made a very conscious decision to take on more variable interest rate debt. That has a little bit more risk associated with that but it actually has a material number/material dollar savings so that helps on the financial side.

Then we have several blocks of IPR savings that reflect for Power a total of $56 million of actual spending reductions. We ate all of the inflation in the business and found an additional $56 million in savings. You can see the Corps and the Bureau and our partners at Energy Northwest really dug in absorbed a lot of inflation and cut $18 million there. We decided based off based on our progress in the first couple of years of the rate period of the 7th Power Plan in energy efficiency to make some cost reductions to energy efficiency and still not compromising the long-term achievement of the five-year average megawatt target. We have been able to reduce some costs in generation inputs and through ancillary services for the balancing area. Also our internal operations – everything from human resources to IT and our supply chain – have taken another $11 million reduction.

And then consistent with my commitment to keep our fish and wildlife spending under control in face of additional spill obligations, we were able to take another $22 million out of our Fish and Wildlife program while trying to be very sensitive to making sure that we are not doing things that will harm our legal obligations or support the actions that really benefit salmon out there in the Columbia [River] basin.

So that leaves us at the end of the day with about $75 million of upward rate pressure that translates into about 3.8 percentage points of rate increase. That is not something I am happy about by any stretch and I know certainly no rate increase is going to make anybody particularly pleased. We will continue to nibble away at these numbers through the balance of the rate period but at least we have tried with a lot of energy and a lot of focus to run the ticker backwards to try to get the rate increase to a manageable level.

SLIDE 8 – BP-20 PROPOSED TRANSMISSION RATES

So just a couple of things I want to mention ah with my remaining time. I want to turn next to on the transmission side. You know we have been trying to manage consciously our leverage on our transmission business line which you know has been on an unsustainable trajectory. Power, as you know, is slowly de-levering from the high 90s to the mid-80s over the next decade.

Transmission unfortunately has been borrowing significantly more than it's been repaying. We were thinking going into our initial proposal that we would actually start taking some significant actions in addition to some financial changes that we are having to address. Our initial proposal might end up as high as 9.5 percent.

A few things have moved our direction here in the last couple months in terms of cash positions and borrowing on the books for transmission. And of course we are quite motivated to help the region come together around a settlement for our rate, for our tariff under the TC-20 process. We believe that in order to sweeten that to bring everyone together to get the process across the finish we line we are willing to offer a 4 percent average transmission rate increase coupled with the rate settlement. Of course the signed settlement deadline is Nov. 30.

I am encouraged with the messages that I have been hearing about the settlement conversation. I think this is a big deal. This will significantly advance BPA's ability to evolved and meet customer's needs efficiently and responsively, run the grid as efficiently as possible so I certainly hope that we get this big step done here in the next few months.

SLIDE 9 – FISH AND WILDLIFE – FISH ACCORDS

Finally I just wanted to mention of course I think many of you know that I decided last month to extend the Columbia Basin Fish Accords for up to four more years through the balance of the term of the Columbia River System Operations review. This was a tough decision in some ways because certainly I know there has been a lot of sensitivity about the Fish Accords and their value and obviously represents a lot of spending. But at the end of the day I really felt that the tribes and the states that we have been working with have been fantastic partners. They have been getting a lot of really really good work done on the ground making a difference for salmon.

Obviously going forward with all of the disputes in play aligned with Idaho and with Montana and certainly to a large extent with Washington although not formally codified this time in an accord and with the lower river tribes, with the Yakima, etc. That is just extremely valuable to us so I felt that that partnership merited an extension of the Accords so I decided to do that here.

The last couple of things I'll mention were just a couple of things that happened this year that I thought were important and at the end of the day took some risks and some liabilities off our books and I think support long-term rate stability and competiveness. The first is that we did successfully resolve longstanding litigation with the California parties. This is litigation that goes back to 2000/2001 West Coast energy crisis sort of the dark cloud for many many years and it was the kind of thing that if it went against us it would have been a significant financial exposure. We were able to settle that and get some dollars in the bank and just basically get all that litigation off the books and I think it was the right thing to do…kind of reboot the working relationship with some of the Southern California utilities. We appreciate that.

Of course we also and this is something I really appreciate customer support for we were able to sign an MOA with Energy Northwest to extend the Regional Cooperation Debt program for up to 10 years and $3.5 billion borrowing capacity. That is a big deal.

And we really appreciate that a. the level of scrutiny and engagement by public power on that to make sure we were making a good decision but also to make sure we continue to hold ourselves accountable for really spending capital as efficiently and as disciplined as possible. Those two things come hand in hand. The fact that we have been able to address our debt capacity does not let us off the hook for being wise stewards and thoughtful spenders of customer dollars.

And then finally I think some of you heard. First just another shout out to our partners at Lower Valley – really appreciated the partnership on Hooper Springs transmission line this year and think this was…Jim Webb and the crew down there decided to build that line and take that expenditure off our books. That was just a great example of innovating thinking, partnering with customers and leveraging our mutual skills. It’s going to save us a lot of money and allows us to continue to deliver federal power into the Jackson area and that is an example of new ways of thinking about it.

SLIDE 10 – FINANCE

Elliot Mainzer: And with that I am going to turn the microphone over to Michelle Manary who is I think many of you know is our new chief financial officer. It’s great to have Michelle working in that capacity. Her 20 years of experience across Bonneville’s Power, Transmission and Corporate organization really is going to be invaluable as we build on the momentum we gained this year in strengthening our financial health. It’s great to have Michelle with us and thank you all again and appreciate your support and enthusiasm. Michelle over to you.

Michelle Manary: Thanks Elliot. I am excited to be at my first of many QBRs sharing our FY 18 financial performance and accomplishments.

SLIDE 11 – FINANCIAL HEALTH OBJECTIVES

So the underpinning of achieving success on the agency strategic objectives of modernizing assets and system operations, providing competitive products and services and meeting customer needs efficiently and responsively, is financial health. This summer we finalized the BPA Financial Plan which lays out in more detail four financial health objectives seen here on the screen. These objectives are cost management, debt utilization, debt capacity and liquidity. One of the main focuses will be to take these financial objectives and weave them into the fabric of BPA creating a culture of awareness about the impacts of decisions people make to these four financial targets.

The first of these targets is cost management. This objective speaks to the need for a healthy cost management discipline throughout the agency where costs are transparent, targets are set and accountability is clear. We are going to work hard to keep program costs at or below inflation over the next decade in order to help BPA be a provider of choice in the future and a dependable business partner for years to come. This is imperative in order to sustain the hard work we have done to bend the cost curve Elliot talked about.

The second objective is debt utilization. In order for a company to be agile and flexible in the changing environment, it cannot be saddled with too much debt. The BPA Leverage Policy, completed in September 2018, creates a strategy to reduce BPA total debt compared to its assets in an effort to strengthen financial health and flexibility. Reducing debt will help BPA lower its interest costs, support its strong credit rating, maintain access to borrowing for the U.S. Treasury, and improve financial strength and flexibility. In the Leverage Policy, BPA set short-term, mid-term and long-term targets in order to strike a balance with the other agency strategic goals.

The third one is debt capacity. In order to keep our assets healthy and expand where needed, BPA needs to have the ability to borrow for these strategic investments. We have limited borrowing authority with the U.S. Treasury so our target is to maintain at least $1.5 billion of borrowing authority at all times. A key part to sustaining sufficient borrowing authority is our partnership with Energy Northwest and the Regional Cooperation Debt program. Elliot talked about our RCD extension earlier which is a key driver to helping us meet this objective in the long run.

And the fourth target, objective, is the liquidity. We updated our Financial Reserves Policy with an important record of decision on how we will phase-in financial reserves when they are below the lower threshold of 60 days cash on hand. This was a process we committed to not only in our strategic and financial plans but in the BP-18 Rate Case Final ROD.

The updated policy addresses what rate actions should be taken when financial reserves fall below a business line’s lower threshold, which is the equivalent of 60 days cash on hand. If business line reserves are below the lower threshold, BPA would initiate a rate action to increase rates until it returns reserves to the lower threshold. A second rate action would trigger to recover business line reserves if they fall below $0. BPA must still make several decisions on how to implement the policy in the next rate case, including the rate mechanisms for collecting or distributing reserves, when those rate mechanisms trigger and the metrics used to determine when a reserves-related rate action should be taken.

SLIDE 12 – AGENCY NET REVENUES

I am pleased to announce that we have ended the year with better than expected net revenues. We ended the year with $444 million above rate case expectations. This includes the $130 million from Regional Cooperation Debt transactions. The remaining gain is due to positive and efficient operational performance from Power and Transmission.

SLIDE 13 – AGENCY FINANCIAL HEALTH

This next slide breaks down our net revenues into total revenues and expenses.

Total expense, shown on the left, is defined as the total expenses related to operations and maintenance, fish and wildlife, energy efficiency, depreciation and interest. In total, we reduced expenses by $387 million across the agency this year. Besides the Regional Cooperation Debt transactions, this is in part due to the budget true-up Mary Hawken addressed in the second Quarter Business Review and additional cost savings found in the business lines which you will hear about later. And Janet Herrin will address how we are continuing these costs reductions in 2019.

On the right is total revenues. Our revenues were higher across both Power and Transmission. Joel and Richard will talk more later about the main drivers behind the $57 million operating revenue increase over our rate case outlook.

SLIDE 14 – FY 2019 FINANCIAL HIGHLIGHTS

Since it is hard for most folks to understand the true state of the business with the accounting treatment for Regional Cooperation Debt, this is a simple breakdown of where the business lines ended the 2018 fiscal year that filters out the effects of our RCD actions.

Starting in the upper left hand box, the Power business line ended the year with expenses $52 million less than the rate case. Looking at the box below it shows they also ended the year $35 million higher than projected revenues, resulting in net revenues of $87 million above the rate case level.

Transmission also had a good year. The upper right hand box shows their expenses came in $19 million lower than rate case and revenues were $38 million higher resulting in net revenues of $57 million above the rate case level.

In the upcoming slides, Richard and Joel will talk about the main drivers of their positive financial performance.

SLIDE 15 – DEBT-TO-ASSET RATIO

These next two slides are the two Key Performance Indicators targets we introduced in January, but do not generally have large movements throughout the year, so we only report out annually. This slide highlights our debt-to-asset, or leverage, ratio. The good news is we improved from last year. Our agency ratio dropped two percent this year to 88 percent; this was due to investing in our assets and Power repaying more debt than they used. However, we have to keep the discipline front and center over the next few rate periods in order to hit the mid-term and long-term goals. We are working hard to invest strategically in our assets while scrutinizing our investments and embracing new technology to get the most value at the least cost.

SLIDE 16 – CURRENT BORROWING POSITION

This next metric I want to cover today is our current available U.S. Treasury borrowing authority. We currently have $2.2 billion available. We used $522 million this year split almost evenly between projects for Power and Transmission. Since our goal is to keep $1.5 billion as a cushion, we need to be very diligent in our management of this fund.

SLIDE 17 – DAYS CASH ON HAND

Days cash on hand. BPA ended the year with $840 million in total financial reserves. This is an improvement of $202 million from last year.

Days cash on hand indicates the number of days BPA can pay its operating expenses, given the amount of financial reserves, basically cash, available. As you can see, we are not releasing our days cash on hand at this time. While we are confident in our total reserves outlook, we are still scrubbing the two categories reserves are put into; reserves for risk and reserves not for risk. Our reserves for risk is the money we have available for operational flexibility as needed, which is the driver for the days cash on hand. Reserves not for risk are funds set aside for a specific purpose like customer pre-pays, the Energy Northwest line of credit and debt service reassignment funds.

When we started our deep dive into our financial reserves forecast errors that have been reported in past meetings, we decided we needed to do a more robust review of how we allocate our reserves into these two categories, including our actuals, and the policies we use to determine that. We know these numbers are important to many of you and are crucial to some of the great work we are doing in our Financial Reserves Policy, and as such we want to make sure we have a good grasp of where we are at before we report these numbers. We will provide updates at future QBRs on this work and where we think we are at.

If you are looking for additional financial details, we have published the Quarterly Financial Package on our Financial Overview web page and we are also going to publish our annual report next week. We post it on our webpage as well.

SLIDE 18 – POWER SERVICES

Michelle Manary: That concludes my financial update. Now Senior Vice President of Power Services Joel Cook will provide more details on Power Services financials and achievements.

Joel Cook: Thank you Michelle. Good morning everyone. I am happy to be here to share Power Services' positive end-of-year financial results. We exceeded expectations by coming in under our expense forecast and maximizing our revenues.

SLIDE 19 – POWER SERVICES EXPENSE

On the expense side, we tightened our belts and implemented cost-management actions across Power that resulted in significant savings for this year and future years. In addition to our cost-management efforts, we also benefitted from Regional Cooperation Debt already mentioned, which reduced debt-service expenses.

Thanks to those efforts, Power's end-of-year financial results for total expense was $179 million less than our rate case forecast.

SLIDE 20 – POWER SERVICES REVENUES

Turning now to operating revenues for the year trended higher than the rate case mainly due to strong surplus energy sales. The above average water supply through quarter three was a large contributor. Our end of year revenue expectations were worrisome earlier in the year, largely due to high market price conditions and persistent dry weather we experienced. But the team did a great job maximizing the flexibility of the federal system to avoid high market price exposure.

The end-of-year total operating revenues were $35 million higher than the rate case.

Combining those two metrics – Power's higher revenues and lower expenses resulted in positive net revenues of $412 million.

SLIDE 21 – HENRY HUB PRICES

Let's now move on to market prices. For most of the year, market prices had a nominal impact on financial performance largely due to the great water year we had. Through Q3, Henry Hub price departures from the rate case forecast were mostly below expectations due to warmer than expected national weather we experienced. However, demand started to pick up towards the end of Q3 as we experienced unseasonably hot weather. As you can see from the chart the January price was a big outlier.

Natural gas storage deficits increased during the fourth quarter; however, it didn't have the impact on the market that you might expect. Market expectations are that strong production growth in FY 19 should be enough to meet any calls on demand over the winter and into next summer. That helps keep prices within reason and close to the BP-18 rate case expectations.

SLIDE 22 – MID-C PRICES

Turning to Mid-C prices. While Mid-C on-peak power prices were relatively close to the BP-18 forecast for the first couple months of 2018, monthly power prices dropped further below the forecast between December and May due to strong water conditions and soft regional natural gas prices.

Prices during July and August rallied to levels well above rate case expectations due to several stretches of above average temperatures in the West and very strong California natural gas prices. With that strong demand for power in the Pacific Northwest and California during the hot weather, on-peak prices hit as high as $300 per megawatt hour. We hadn’t seen that for awhile. As the weather shifted back to normal during September, the Mid-C price ended relatively close to the rate case forecast.

SLIDE 23 – NET SECONDARY REVENUE

Now we get to net secondary revenues, one of our most variable financial metrics.

As I said before, water supply exceeded rate case expectations which translated into more inventory. For most of the year this propelled monthly net secondary sales beyond expectations. However, the runoff came earlier than expected in May, which shaped inventory sales into less valuable spring months. This was further exacerbated by a persistent, dry summer. The weather, coupled with the spikes in market prices we saw in California, created a scenario for considerable losses through expensive market purchases. Thankfully, the expertise in within our group significantly helped mitigate those losses.

SLIDE 24 – POWER SERVICES CAPITAL

Now moving on to capital. This chart demonstrates capital execution and the work planned versus completed on assets at the federal dams. The Power Capital expenditures ended at $44 million less than the rate case forecast.

Reclamation underspent significantly from their rate case request. They were down under by $52 million driven largely by project delays, including hold-ups on the Grand Coulee Firehouse and work at the Keys Pumping Station and also moving some schedules on some large generators at Grand Coulee.

The Corps exceeded their rate case by $7 million due to strategic project acceleration at The Dalles, Ice Harbor, John Day and some Dworshak work.

This slide also shows completed versus planned assets. Four projects missed their physical completion milestones this year largely due to updated project scoping.
BPA and the Corps and Reclamation took several steps in 2018 to revise the system asset management plans in order to get to more achievable work plans and capital spending forecast.

SLIDE 25 – FEDERAL HYDROPOWER RELIABILITY

Moving on to reliability. We measure federal hydropower reliability using the forced outage factor. This reflects the percentage of hours the federal system is not available due to unplanned outages.

We stayed steady through the end of the fiscal year and as a result, met the end of year target. It was a good job for our hydro system.

SLIDE 26 – COLUMBIA GENERATING STATION RELIABILITY

The key performance indicator for Columbia Generation Station captures the percentage of time the nuclear generator is available by comparing days on line to scheduled non-outage days. Despite a few bumps, we exceeded the target. And there was one unplanned outage in May 2018. So good performance from CGS.

SLIDE 27 – ACCOMPLISHMENTS

Finally I am going to talk about some of the accomplishments for the year. Beyond Power's financial results, I'm happy to share some of the other highlights.

For one, we completed the enhanced Resource Program. The purpose of the program is to assess BPA's need for power and reserves and develop an acquisition strategy to meet those needs. We called it the 'Enhanced Resource Program' this year because we dug deeper into the data and applied additional considerations. We are using the insight gained from the Resource Program to assess potential changes to our energy efficiency portfolio. This will help us better meet our long-term system needs consistent with our strategic plan.Insight from the Resource Program coupled with early achievements in '16 and '17 toward the Northwest Power and Conservation Council's Seventh Power Plan goals are helping us keep energy efficiency costs down in the next rate period.

We also as Elliot mentioned completed the PGE Capacity Agreement. Under two five-year agreements beginning in January 2021, BPA has agreed to sell PGE up to 200 megawatts of surplus clean hydropower generated from our federal system. This is an example of how we are contributing to regional decarbonization efforts. PGE had a need and they had a couple of options, but they were also encouraged by some of their stakeholders to choose a low carbon option. Until the PGE deal this winter, BPA had not done any long term capacity or energy type deals since the early 1990s. This supports our strategic objective of increasing revenue through new market opportunities for clean capacity.

And finally river operations. Managing the court mandated change in spill operations created some operational and marketing challenges that BPA and our partners had to respond to in a very short time period. We effectively navigated a challenging water year that was robust for many months, but turned dry during the late spring and summer. We were able to anticipate the changing water conditions and strategically position BPA. We used our limited ability to shape generation daily, weekly and within the month to meet our non-power obligations while at the same time helping to meet our firm customers loads. Although we met the challenge this year, I am concerned about the impact future low water years could have on our ability to meet both spill and other obligations.

Overall it was a great year for Power Services, and I'm proud of what we were able to achieve despite tightening our spending. I look forward to keeping you updated throughout the fiscal 2019 as we continue to deliver on our strategic goals.

SLIDE 28 – TRANSMISSION SERVICES

Joel Cook: Now I am going to turn it over to our Senior Vice President of Transmission Services. Richard Shaheen is going to give you an update on the transmission side.

Richard Shaheen: Alright thank you Joel and team and good morning to everyone. I appreciate the opportunity this morning to share Transmission's positive 2018 year end results. I will start my report with an overview of transmission finances, then look at reliability results and wrap up with a few of transmission's accomplishments.

SLIDE 29 – TRANSMISSION SERVICES EXPENSE

Turning first to slide 29, the format for these next few financial slides is similar to Joel's power financial slides showing the fiscal year and the BPA-18 Rate Case projections per month versus our actuals per month.

First our expenses in fiscal year 2018 were 2 percent lower than rate case resulting from successful cost-cutting controls in the transmission organization and our corporate partners. Our interest expenses were slightly lower than our rate case and our depreciation expense were slightly higher. This fiscal year was a story of setting priorities and bending the cost curve downward. For the full year as noted in the upper right hand corner of the slide, BP-18 Rate Case projections for transmission was $1 billion 43 million with the resulting years actuals equaling $1 billion 24 million for a variance of $19 million dollars less than expenses projected.

SLIDE 30 – TRANSMISSION SERVICES REVENUES

Turning next to slide 30 and transmission's revenues. Revenues in fiscal year 2018 were mostly above monthly rate forecast. The end of year revenues were 3.6 percent above rate case, which is consistent with our forecast communicated at the third quarter QBR. Our net revenues were higher due to higher network load than had been assumed in the rate case. Network load was higher due to the temperature differentials such as the hot weather we saw this summer and the duration of higher temperatures that was built into the revenue projection. So the full year as noted in the upper right hand corner the BP-18 rate case projections was $1 billion 52 million with the year's actuals equaling $1 billion 90 million for a variance of $38 million more in revenues than projected.

NOV. 7 QBR TRANSCRIPT

SLIDE 31 – TRANSMISSION SERVICES CAPITAL

Turning next to slide 31 and transmission's capital expenditures and work completed. Two things are depicted in this slide – our capital spend and our work plan progress. Actual spending this fiscal year was approximately $100 million less than rate case driven primarily by the advantageous business decision Elliot mentioned earlier to transfer construction work to Lower Valley Energy for the Hooper Springs transmission project. This accounted for about a third of the difference. The rest came as a byproduct of resource and outage constraint and non-critical projects being put on hold to accommodate customer compliance projects as well as internal process efficiencies. In total we were able to accomplish 94 percent of the work we had planned in our asset portfolio and approximately 8 percent of the planned capital expenditure.

SLIDE 32 – TRANSMISSION RELIABILTY – SAIFI

Now turning to slide 32 and transmission reliability. In reliability we successfully met our fiscal year 2018 target for both low and high voltage lines. You can see on the slide our system average interruption frequency index, or SAIFI, results which measures the frequency of outages were better on both the low voltage…on both line voltage populations. We exceeded our goal for the annualized average interruptions per line for the year.

SLIDE 33 – TRANSMISSION RELIABILTY - SAIDI

Turning to slide 33. Shown are the positive results of our system average interruption duration index, or SAIDI measure, which looks at the annualized duration of outages per line. Again the lower the better. And again both voltage populations exceeded our goal. In total, for each of the four measures BPA ended the year better than our most recent 10-year historical median. This was driven partly by milder Mother Nature related challenges such as weather and fire conditions but also continuing our analysis improvements and management of the grid particularly in vegetation management and in maintenance.

SLIDE 34 – ACCOMPLISHMENTS

And lastly turning to slide 34 and some of the 2018 transmission accomplishments. In the area of reliability coordinated services. A series of events changed the landscape of reliability coordinator services in the Western interconnection required BPA to re-evaluate Peak Reliability's ability to continue in its role. Ultimately, Peak announced they will wind down their full services and transition RC responsibilities to alternative providers by the end of 2019.

Upon Peak's decision BPA along with other transmission operators in the Pacific Northwest set their option and chose the California Independent System Operator as our future reliability coordinator starting in November 2019. CAISO is going to become the RC for itself and much of California in July of 2019. BPA is actively participating with the CAISO RC working groups to ensure the continued reliability of the Western interconnection going forward.

Next TC-20. Last year BPA completed a pro-forma gap analysis effectively to assess how our transmission tariff differs from the FERC pro-forma tariff as well as identify the areas we want to standardize. Afterward we launched the TC-20 process to revise our tariff. Our goal is to align our business processes with industry standards furthering our strategy and enable new tools, technology and processes that will increase our efficiency and help take advantage of opportunities in our rapidly changing industry.

As Elliot mentioned we began TC-20 settlement negotiations with customers at the end of fiscal year 2018. We continue to work diligently with customers to reach a settlement on the terms and conditions for a new tariff with the aim of all transmission customers converting their service to the new tariff. This is a critical part of BPA’s strategic plan and it will align our business processes with industry standards furthering BPA’s strategy, enable new tools, technology and processes.

In the area of planning work, first in fiscal year 2018, transmission and power collaborated to develop a tariff-based commercial response to long-term transmission requests to meet certain commercial obligations under our tariff. We implemented the transmission integrated program process which one included changes to our base case for long-term firm ATC, or available transmission capability, and allowed us to identify increases to long-term transmission inventory across BPA’s network. Two it accommodated a majority of the NT load or resource forecast. And three it allowed conversion of 975 megawatts of long-term conditional firm service to long-term firm service delivering on our quote path to firm process under our tariff.

Second evolving demand. In FY 18 we saw a significant increase in the number of solar generation interconnection requests. 44 total projects with an associated 5,562 megawatts.

Demand continues to be high for rapid load growth such as data centers and we’re working with customers in local communities to identify and plan for this load as early as possible in a proactive manner.

Let me conclude by offering my thank you and congratulations to the entire BPA transmission organization and our BPA partner organizations for delivering the great results for fiscal year 2018. Thank you.

SLIDE 35 – FY 2019 PREVIEW

Richard Shaheen: I’ll now turn it over to Janet Herrin, our COO, who is going to share some highlights of what to expect in 2019.

Janet Herrin: Thanks Richard and good morning. You heard about our many great accomplishments for fiscal year 2018 today. So now I want to give you a preview of what to expect in fiscal year 2019.

SLIDE 36 – 2019 AGENCY NET REVENUES

In the second quarter of fiscal year 2018, we shared our plan to reset spending levels to control our cost escalation. And earlier today you heard from Michelle how we made progress on our strategic plan cost-management objective for 2020 and 2021 through the IPR process. We're applying those same principles to 2019.

We currently anticipate that our agency net revenues will be $127 million higher than our rate case forecast.

SLIDE 37 – 2019 AGENCY FINANCIAL HEALTH

This is in large part due to lower forecasted expenses as we continue our cost-management efforts from fiscal year 2018 into 2019. Regional Cooperation Debt actions, described by Michelle earlier, will also help lower our expenses. Together, our total expense reduction is $214 million.

The expense reductions will help offset an expected decline in our revenues. Lower-than-expected customer loads and market prices will persist in 2019 driving down anticipated revenues by $87 million. We will continue to look for ways to maximize the value of our secondary revenues as we have done this past year. One way we are doing this is through our grid modernization projects.

SLIDE 38 – GRID MODERNIZATION

Fiscal year 2018 was a busy year as we worked on setting the foundation for our Grid Modernization Key Strategic Initiative. I want to share a few projects that are underway and how our investment in these projects will add value and help support BPA's long-term commercial success.

The first set of projects is called mission critical information technology. These are the projects to modernize the systems BPA needs in order to do its core power and transmission functions today, as well as to prepare for the future. It includes the infrastructure, or hardware, that our business applications run on. We will be updating the equipment, as well as the way we plan, design, acquire and complete our IT projects. These projects serve as the backbone for all of the other grid mod projects and are scheduled to be completed first.

Another area we are making progress is with our outage management projects. They provide a single point of coordination for generation and transmission outages with our partners at the Corps and Reclamation. The system will reduce the need to schedule separate outages at the generating projects and their adjacent transmission facilities and lines. It also will eliminate manual, and often duplicative, data entry and provide more up-to-date planned outage updates to everyone involved.

The final project I want to share with you is one that will improve the control, accuracy and performance of automatic generation control, or AGC. AGC is how we regulate, in real time, the power output of generators within our control area. These improvements will allow us to maximize how we deploy these resources. The increased net revenue benefit will be determined by water and market conditions as well as the demand for within-hour flexibility products.

Grid modernization is an agency-wide priority and our success in this effort directly supports our ability to achieve our other strategic goals, from selling competitively priced power products and services, to meeting our transmission customer needs efficiently and responsively. We will continue to share updates on progress throughout the year.

SLIDE 39 – PUBLIC ENGAGEMENT

Janet Herrin: Now I am going to turn it over to Scott Simms who is going to cover upcoming processes that you can be involved in.

Scott Simms: Thank you very much Janet. And thanks to all the folks participating back in Portland. So turning back here to the BPA Spokane office and the final elements of our call today I am going quickly share where you can join us in meetings and processes in FY 2019, provide a heads up on current comment periods and we'll close today with a brief Q and A exchange.

SLIDE 40 – PUBLIC PROCESSES

As Elliot discussed earlier, we are continuing to engage the region on whether or not BPA should join the Western energy imbalance market, or EIM. Our next meeting will be on November 14 at 1:30 p.m. Pacific time both in person and by WebEx.

On December 7 at 9 a.m. Pacific time, BPA will review its results from this year's South of Allston bilateral dispatch pilot. This is the final year of the two-year pilot that was exploring demand-side management to manage congestion on the South of Allston path.

SLIDE 41 – COMMENT PERIODS

Turning to comment periods, we have two closing this month. BPA has prepared a draft environmental assessment on project it plans to fund to capture, recondition and release of post-spawn Snake River steelhead. This comment period closes November 13.

The second comment period, closing November 23, is about BPA helping to fund a translocation of up to 50 Columbian white-tailed deer from an island in the Columbia River to conservation lands in Columbia County, Oregon.

Details for both the events and comment periods I have mentioned today are available in our event calendar on bpa.gov.

SLIDE 42 – QUESTION AND ANSWER

Scott Simms: So this concludes today's presentation. Now we are going to start answering questions that have come in during the presentation today. We want you to bear with us as we try to bounce between Portland and Spokane.

You can still submit questions by clicking on the "chat" button on the upper-right-hand side of your screen, enter your question, and press "send." Your questions will be sent to the BPA host.

So we currently have two questions. The first one has come in from Fred Huette, Northwest Energy Coalition. I think Fred's question may be one of the longest questions we have received in the QBR process so will you bear with me here as I read through it. In recent years, during spring runoff, the Columbia Generating Station has been the only thermal plant running in the region. Especially when the market is below $20/megawatt hour. As a high operating cost resource, Columbia adds to oversupply and depresses prices at the Mid-C for BPA and other surplus sales, and the extra running time raises the probability of forced outages as in the May 2018 example. Is BPA willing to assess this situation and work with Energy Northwest on scheduling planned outages when river runoff and market conditions indicate that it's prudent? And I believe that we are going to have Joel Cook in Portland answer this question. Joel.

Joel Cook: Thanks for asking the question. So as you may know when we do a refueling outage at CGS every other year we are targeting that spring runoff window to take advantage of those low price periods. But in addition to that in this past year we requested CGS to restudy the ability to reduce load during the spring runoff and/or provide a more flexible operation at different levels. So this as you might understand has some operating implications. So one from just the plain operations moving the plant around and potentially causing less reliability. The other is the implication on the fuel supply itself. The fuel supply is planned many years in advance and if we don't completely burn that fuel it provides a less efficient operation from our fuel expense side of the ledger. But the bottom line is, the short answer is, we have a willing partner in CGS support studies and more flexible operations and we look forward to implementing that in the future.

Scott Simms: Thanks very much Joel. We have a next question from Randy Gregg. And the question is: What forum will be used to release actual end of year FY 2018 reserves for risk and days cash on hand by business line? And I believe we are going to have Michelle Manary here in Spokane answer that question.

Michelle Manary: Yes. So we expect to use the Quarterly Business Reviews as we said before and we will keep you updated on when that is as well as any other type of webinar or workshop is needed as we see the results.

Scott Simms: Great thank you Michelle. Do we have any additional questions? If you want to submit a question in more detail later please email us at communications@bpa.gov.

SLIDE 43 – THANK YOU

Scott Simms: Those questions already submitted via today's WebEx don't need to be resubmitted, but if you want to clarify, that would be great. We'll be posting follow-up answers to all these questions on the QBR webpage in the coming weeks, along with a recording of today's meeting.

If you have a topic you think warrants further discussion, such as the depreciation study, we are interested in ensuring that you get that information. Please email communications@bpa.gov with your topic ideas and we will look at the best way to get that information back out to you whether its posted responses or short meetings like we held Oct. 3 on our financial processes.

So in conclusion we really appreciate you listening today. And we appreciate you engaging with us whether in this forum or others. We really look forward to you joining us on January 29 when we kick off our fiscal year 2019 series of QBRs.

And with that Thanks, everyone. Have a great day.

SLIDE 44 – FINANCIAL DISCLOSURE