PLATTE RIVER POWER AUTHORITY

Minutes

Regular Meeting of the Board of Directors

Thursday, August 26, 2010

The Platte River Power Authority Board of Directors' meeting convened at 8:52 a.m. on Thursday, August 26, 2010, in the Platte River Power Authority boardroom.

BOARD MEMBERS:

Present: Mayor Bill Pinkham and Reuben Bergsten representing Estes Park; Mayor Cecil Gutierrez (Secretary) and Ralph Mullinix (Chairman) representing Loveland; Mayor Bryan Baum and Tom Roiniotis representing Longmont.
Absent: Mayor Doug Hutchinson and Brian Janonis
Quorum present? Yes

PRESENT FROM PLATTE RIVER'S MANAGEMENT STAFF:

General Manager, Brian Moeck; and General Counsel, Joe Wilson. Division Managers: John Bleem, Customer & Environmental Services; Mike Dahl, Electric Operations; Jason Frisbie, Power Production; and Dave Smalley, Financial Services.

OTHER PLATTE RIVER STAFF IN ATTENDANCE:

Executive Assistant, Esther Velasquez; Human Resource Manager, Dave Green; Controller, Ed Doherty; Finance Assistant, Brandi Cross; Community and Media Relations Specialist, Rae Todd.

GUESTS AND MEMBERS OF THE PUBLIC:

City of Longmont Marketing and Customer Services Manager, Deborah Cameron; City of Longmont Power and Communications (LPC) Business Manager, Susan Wisecup; and Fort Collins resident Eric Sutherland.

ACTIONS:

(1) Call to Order. Chairman Mullinix convened the meeting at 8:52 a.m.

Due to beginning the meeting eight minutes early, the Chair suggested agenda item 2 (*Public Comment*) be moved to after the Legal Counsel Report affording any members of the public arriving after 9:00 a.m. the opportunity to speak.

(2) Approval of the Regular Meeting Minutes of July 29, 2010.

Director Roiniotis moved to approve the meeting minutes of July 29, 2010; Director Gutierrez seconded the motion. Motion passed 3-0. Directors Pinkham, Baum, and Mullinix abstained because they were not at the July meeting.

(3) Legal Counsel Report. General Counsel reported the following:

Oil and Gas Development at Rawhide. Retained counsel, Jamie Jost, met with Platte River staff and toured the Rawhide site on August 4. Staff is still in the process of identifying geologic or engineering experts to provide insight into development risks. Staff is optimistic that by the September Board of Directors' meeting more details will be available so that the Board can provide direction concerning development.

Development activity also affects adjoining property held by the City of Fort Collins. Staff continues to converse with city staff on this issue.

PUC Transmission Docket. Last month Counsel mentioned the pending Transmission Planning Dockets that are before the Public Utilities Commission (PUC). Platte River and other transmission providers continue to urge the PUC to build the rule around the Colorado Coordinated Planning Group's (CCPG) planning process. At present, the PUC seems willing to defer to the CCPG process as a starting point. The rulemaking hearing was scheduled for September 9, but at the request of several entities has been rescheduled for November 5. Comments are due October 15, with replies due October 29. The CCPG is encouraged by the extension and will be able to better understand the rule and provide comments.

Organic Contract and Power Supply Agreements. The Organic Contract, partially executed this morning prior to the Board meeting, should be fully executed by all parties early next week. The Power Supply Agreements between each Municipality and Platte River have been fully executed. Pertinent information from the Transmission Facilities Agreements has been incorporated into the Power Supply Agreements and the Transmission Facilities Agreements have been terminated.

(4) Public Comment. No members of the public offered comment. However, Director Roiniotis introduced Ms. Susan Wisecup and Deborah Cameron of Longmont Power and Communications.

(5) Legislative and Regulatory Report. The General Manager reported on recent developments at the national level.

Federal. Congress is in August recess. The Senate has announced a lame duck session and the House will also likely declare a lame duck session.

APPA's CEO Climate Task Force has recently created a proactive eleven-member working group assigned to promote a public power position on climate change initiatives. The working group is studying a white paper outlining a plan to meet greenhouse gas emissions reductions for coal-fueled electricity sources (a potion of which was included in the Board packet). The Retirement Plan Act for Coal-Fueled Electricity Sources (REPLACES) promotes the reduction of greenhouse gas emissions by requiring the retirement or retrofit of all coal-fueled electric generating units. The plan calls for a performance standard base system, not a cap-and-trade system and delineates the retirement or conversion of coal-fired generation units based on age. Plants commissioned and operational prior to 1960 would either be retrofitted or retired by

2020 and all other plants would follow in ten or fifteen year increments based on age. Rawhide and Craig would fall into the 2045 timeframe for retirement or retrofit. APPA is working on a straw man proposal for the working group to consider at its next meeting.

The General Manager also mentioned that the Environmental Protection Agency's timeline for various ozone, SO_2, NO_X, CAIR (now the transport rule) water, particulate, ash, carbon dioxide (CO_2), etc., requirements is a fulltime job for several staff members to monitor and provide input to management in order to make informed decisions.

Director Mullinix mentioned that as all units convert to natural gas—home heating cost will likely increase significantly.

The General Manager mentioned that a positive note to the proposal would be that entities would have a better roadmap for planning than the current climate of uncertainty.

Mayor Bill Pinkham mentioned that the east coast has a significant number of older plants and to convert them would impact manufacturing costs.

Mayor Cecil Gutierrez mentioned that natural gas is not a renewable resource, questioned dependency on other nations to provide supply fuel, and believes that conversion to natural gas would only be a short-term solution.

The General Manager stated that seventy percent of U.S. generation is supplied by investor-owned utilities; it is likely those utilities would fuel switch or phase out plants to save on costs. Economically, conversion to gas would be less capital intensive than trying to meet strict emissions regulations on older coal plants.

Mayor Bryan Baum inquired about the viability of large-scale hydrogen fuel sources.

John Bleem stated that hydrogen is an energy medium rather than a new energy source; hydrogen is typically derived from natural gas at this time. Hydrogen technology is still evolving, but it may become a viable option for power generation in the future.

State Issues. The General Counsel mentioned that several ballot initiatives will be on the November ballot. As mentioned at previous Board meetings, Amendment 60 and 61 along with Proposition 101 may negatively impact Platte River, the Municipalities, or both.

Proposed changes to the Taxpayers' Bill of Rights in Amendments 60 and 61 would directly affect Platte River. Amendment 60 would subject enterprises such as Platte River to property taxation, which would be a multi-million dollar expense that would need to be recovered in rates. Essentially, this initiative would reduce property tax rates while increasing electricity rates. Amendment 61 would not allow enterprises to issue revenue bonds without voter approval at a November election and would limit the term to ten years.

The Fair Campaign Practices Act allows political subdivisions to adopt resolutions in favor of or opposition to ballot issues. Traditionally, Platte River has not adopted resolutions taking a stance on ballot initiatives, but due to the direct impacts to Platte River, the Board of Directors has the option to do so if it so chooses. Many entities either have or are planning to adopt resolutions in opposition to these initiatives.

Director Baum inquired about Platte River's bond rating and its ability to issue bonds in the future.

Chief Financial Officer Smalley responded that it would likely be more a matter of when to issue bonds and the ability to do so rather than the impact on bond ratings. Being forced to issue bonds for a shorter term could be less risky for bondholders assuming the Board is willing to raise rates to cover short-term bond issuances.

Director Pinkham stated that there is concern as to whether or not bond agencies would still be interested in doing business in Colorado.

The Chairman inquired if the Board wanted to proceed with a resolution at the next Board of Directors' meeting. The Board unanimously agreed that Counsel should draft a resolution to bring before the Board in September.

Several Board members inquired about how much of a rate increase in addition to the current estimated increase ratepayers could be expected if these measures are adopted.

Although staff has not actually run the numbers, the Chief Financial Officer stated that a very rough estimate would likely be an additional 20 to 25 percent on top of already proposed rate increases.

Regional haze. Division Manager John Bleem stated that regional haze is not a health issue but rather a visibility issue, impacting quality of life from that perspective.

The State of Colorado must act in accordance with federal emission reduction requirements to meet rules under the Clean Air Act before the end of the year or federal regulators will set the rules for Colorado. Draft rules for Best Available Retrofit Technology (BART) plants have been posted by the state. Craig must reduce NO_X by about 17 percent and Selective Non-Catalytic Reduction (SNCR) technology has been recommended. The cost for both units at Craig is estimated at about $30 million. If SNCR technology does not work, the plants may be required to use Selective Catalytic Reduction (SCR) technology to reduce NO_X. Selective Catalytic Reduction technology is significantly more costly, approximately $200 million per unit. These costs do not include estimated O&M cost increases.

Tri-State is currently testing the SNCR technology, at a cost of $1 million, to determine if emissions goals can be met at Craig. If the technology works, it is likely that no additional NOx reductions will be required (beyond SNCR) to meet upcoming ozone requirements. O&M costs are estimated to be $4 million per year (both units). Installing SNCR technology does not preclude the possibility that SCR technology will still be required at a later date. If the SNCR tests work, Platte River's portion of the capital expense will be 18 percent of $30 million (about $5.4 million). If SCR is required on both units, Platte River's cost could be 18 percent of $400 million (about $72 million). Additionally, installing SCR on the Craig units would require at least a 15-week outage. Purchased power replacement costs would be very high. Ongoing operating costs would also be very significant for SCR. Estimates for this cost are still being developed by Tri-State (as operator).

With recent upgrades to NO_X controls, Rawhide should be able to meet new emissions rules over the near-term without implementing additional NO_X reduction technology. Nonetheless, it is possible that Rawhide will be required to employ new technologies to meet ozone requirements in the 2016 time frame. Details of new ozone rules will be available in the next couple of years.

(6) July Financial Report. The Chief Financial Officer reported on the July financial results.

Net income for the month of July was $2.3 million. This represents a $0.7 million above-budget variance resulting from above-budget operating revenues and below-budget operating expenses (including depreciation). Net income for the year has increased to $1.5 million and continues to lag budget by $0.8 million.

Operating revenues totaled $17.4 million during July and were $0.5 million above budget. Below-budget municipal sales were more than offset by above budget surplus sales. Municipal sales were $0.8 million below budget with energy deliveries and billing demand below budget 4.7 percent and 3.4 percent, respectively. Short-term surplus sales were $1.4 million above budget, primarily due to peaking unit sales to Xcel Energy and higher generation from the thermal units. The contract sales were below budget $0.1 million with Tri-State taking no energy during the month.

Interest and other income was slightly under budget in July with lower-than-budgeted interest earnings offset by above-budget other income. Reinvestment of reserves at historic low interest rates continues to negatively impact interest earnings.

Operating expenses excluding depreciation in July totaled $12.0 million and were slightly below budget with above budget fuel expense offset by below budget production expenses. Fuel expense was $0.5 million above budget as a result of higher natural gas expense for the peaking units and above-budget thermal generation. Production expenses were below budget $0.5 million resulting from lower operations and maintenance expenses for Rawhide Unit 1. Transmission expenses were below budget and administrative and general expenses were slightly above budget.

Debt expense of $2.3 million was slightly below budget for the month. Debt service coverage was 2.44 times versus the budget of 2.16 times for July and is 1.44 times for the year versus a budget of 1.52 times.

Capital additions totaled $5.6 million in July and exceeded budget by $2.8 million. This variance is due to a catch up on the transmission projects. Year-to-date capital additions total $40.4 million and are $4.7 million below budget.

Resource output from the thermal units during July was 5.2 percent above budget. Rawhide Unit 1 ran well for the month and reported a net capacity factor of 97.4 percent. Craig Units 1 and 2 also ran well with net capacity factors of 94.9 percent and 95.8 percent, respectively. The peaking units generated 22,387 MWh and wind generation totaled 3,773 MWh during July.

(7) Wholesale Rate Structure Study. John Bleem, Customer & Environmental Services Division Manager spoke about recent developments in assessing possible new rate design options.

As mentioned at previous meetings, revenue requirements from wholesale rates are comprised of several items (debt service, fuel, etc). Most entities recover costs through wholesale rates (such as peak demand and energy charges), but some entities recover their costs based on project participation levels or a split of total costs for joint projects. On the retail side, all the Municipalities have different rate designs for their residential, commercial and industrial customers.

The current wholesale rate contains a demand charge of $12.53 per kilowatt billing demand and is based on one coincident peak hour each month. The energy charge of $0.0202 per kilowatt-hour is applied to all energy used for the month. As technologies such as smart grid and distributed generation advance, some customers will likely have more capability to respond to electricity price signals. Using the current wholesale rate, wholesale revenue losses from peak demand control significantly exceed generation savings. Net lost revenues from customers who can respond to price signals may lead to increased rates for customers that cannot respond.

The City of Fort Collins has a peak reduction goal of ten percent by 2020. The current wholesale rate would increase to recover lost revenues as a result of clipped peak. The relatively small increase in surplus energy due to peak clipping would not offset lost revenues—as short-term capacity cannot be resold in the wholesale market. Additional rate inequity occurs when the four Municipalities do not clip peak at the same rate.

The goal of a rate structure change is to align the rate with the marginal or avoided cost of wholesale supply. Re-allocation of base load fixed costs and incorporation of time-of-use pricing may promote better cost/rate alignment. Also, clipping peak does not typically reduce carbon dioxide (CO_2) emissions. In the future, increased CO_2 costs would be recovered through an energy charge.

As mentioned at previous Board meetings, Platte River has retained a rates consultant (Utility Financial Solutions or UFS). UFS recommends sending wholesale peak price signals that are more in line with long-term marginal generation cost (i.e. cost for the next resource and associated transmission). They also suggested recovering fixed costs for base load generation resources when they are utilized, rather than only during a one-hour monthly peak. Including time-of-use pricing to reflect seasonal and daily cost trends was also encouraged. Updates to the rate structure could promote a better price signal, reduce subsidies and cost transfers, align costs with the wholesale surplus market, and advance a more stable revenue recovery.

Director Roiniotis mentioned that if the rate is accurate, it will drive the correct behavior and will proportionally lower wholesale costs. He would like to see what the consultants consider the ultimate compromise between accuracy and simplicity.

Director Mullinix stated that at some point the rate structure would have to change. He suggested a very gradual change so that large customers do not have stranded investments. In time they will have to adjust, but it is prudent not to make a change too abruptly.

At the last Board meeting, Director Bergsten indicated he would like to see how costs are allocated to demand and energy rates. In response, the Chief Financial Officer provided information on how the rate is currently developed. Purchase power, reserves, transmission expense, fixed Windy Gap, and debt expense is allocated to demand, while fuel, other production costs, and A&G are allocated to energy. Adjustments are made for surplus sales, interest income, transmission leases, and large customer revenues.

After some discussion, the Board of Directors unanimously recommended staff proceed with the next steps in the study: complete internal analysis, seek additional consulting support, and continue to work with Municipal staffs to develop new wholesale rate options.

(8) Capital Projects / Ten-year Plan. Jason Frisbie, Power Production Division Manager, provided an update on Yampa and Rawhide major capital generation projects.

Between 2011 and 2020, two major and four minor outages are planned for Craig Units 1 and 2. Major projects include the following: Unit 1 and Unit 2 HP-IP turbine rotor upgrades, dust suppression in crusher areas, Unit 2 generator rewind, Unit 2 boiler component replacement, limestone storage and handling equipment, Unit 1 generator stator bar kit, and installation of a railroad loop, at an estimated cost of $8.6 million.

The ten-year capital projection for Rawhide is as follows: one Unit 1 major outage and two minor outages, Windy Gap Firming Project, and an anticipated new generation resource, at an estimated cost of $138 million in the 2018 timeframe. The three minor outages include a burner management system, generator rotor replacement, secondary superheater pendant replacement. An estimated $3.5 million for a dry bottom ash removal system in the event environmental legislation classifies ash as a hazardous waste. Additionally, American Association of Railroads (AAR) rules specify that railcars over a certain age, regardless of use, must be retired; therefore, all railcars currently in use will have to be replaced in the next ten years.

Mike Dahl, Electric Operations Division Manager, provided an update on Platte River's ten-year major capital transmission projects.

In cooperation with Tri-State and Poudre Valley REA (PVREA), Platte River will begin rebuilding the Tri-State transmission line coming into PVREA's Trilby substation. This is a radial substation, which will require Platte River to back-energize the underground cable system to the recently placed transition pole so that PVREA customers will continue to have power while the Tri-State overhead transmission line is rebuilt this winter. High-voltage 230kV equipment will be installed at the Horseshoe substation to feed electricity from Fort Collins to Loveland. Estimated project cost: $5 million.

In June 2011, the Longmont transmission project should be complete with a budgeted cost in 2011 of $6.3 million. The Fordham Substation expansion project is progressing and is scheduled to be energized in July 2011.

The City of Fort Collins Portner transmission and substation project is scheduled to be energized in October of this year. The city also would like to add a distribution delivery location at the Timberline Substation. In addition, a second 230kV transformer installation at this location seems sensible considering the current transformers are nearly forty-years old. The new transformer should be installed in 2013 and the old transformer replaced in 2015. Estimated project cost for all of these items: $6.4 million.

The Loveland East Substation expansion includes creating a ring bus to improve reliability, additional circuit breakers and isolation switches and a new switchgear building for distribution circuits coming out of the substation. This project should be complete early next year. Loveland's Boyd Substation is also scheduled to have an additional transformer installed. And, the Loveland Crossroads Substation will likely have a new transformer connected in 2012. Estimated project costs: $217,000, $2 million, and $400,000 respectively.

Funds have also been budgeted for new substation walls at several locations to improve security. Several forty-year-old circuit breakers are also scheduled for replacement. Estimated project costs: $1.1 million and $400,000, respectively.

After additional analysis of transmission interruptions at the Laporte Substation, staff determined that interruptions are rare, and therefore this expansion project could be eliminated to save an estimated $8.5 million over the next three years. A portion of the savings will be applied to installation of anti-galloping devices on the transmission lines coming from Rawhide. Anti-galloping devices are installed on the conductor to spoil the flow of air across the conductor to keep ice from forming in the shape of a wing. As wind velocity increases, the ice buildup creates conditions in which the lines clash between the conductors often resulting in tripped lines or outages.

Three active single-phase transformers at Rawhide are 35-years old and nearing their life expectancy, so in 2019 the units are scheduled to be replaced during the 2019 outage. Estimated project cost: $9 million.

(9) Management Report. The General Manager provided an update on the following:

House Bill 1365 signed by Governor Ritter in May 2010 required Xcel Energy to submit to the Public Utilities Commission (PUC) a plan by the end of August (2010) for reducing emission from its Colorado coal-fired generating units. The provisions of the plan called for a 70 to 80 percent reduction in annual NO_X emissions as measured from 2008 levels and encompass a minimum of 900 megawatts or 50 percent of the utility's Colorado coal-fired units, whichever is smaller.

The plan submitted by Xcel calls for: adding emissions controls at three plants that have a combined capacity of 951 megawatts; switching one plant that has a capacity of 111 megawatts to natural gas; retiring six plants that have a combined capacity of 903 megawatts. (The six plants to be retired are relatively old. Their average age at shutdown will be 55 years. In comparison, Rawhide Unit One has been operating for 26 years). The Plan will not be fully implemented until the end of 2022. However, with the start up of Comanche 3, the largest coal-fired plant in Colorado, Xcel's net reduction in coal-fired capacity will only be about 200 megawatts. During the writing of the bill, Xcel negotiated with the PUC to assure that all costs of executing a plan would be recoverable through increased electric rates.

A recent *Denver Post* article seems to imply an overall rate increase of only one percent. This estimate is clearly incorrect; Xcel estimated a 4 to 6 percent increase annually over the next ten years. Though Xcel now estimates an annual increase of one percent annually, it is still a relatively large discrepancy. It is unlikely that a one percent increase would fully recover fuel switching and plant retirement costs. Nonetheless, several individuals have inquired how this bill will impact Platte River. This bill has no direct impact on Platte River.

The General Manager pointed out that residential rates in Estes Park, Fort Collins, Longmont, and Loveland are 7, 50, 76, and 60 percent lower than Xcel's average summer rates.

The **Yampa Project** Participation Agreement may surface as an item of interest in the near future. Xcel offered their YAMPA Project capacity for sale about a year ago—the Platte River Board had no interest in obtaining additional capacity at the time. There have been no new developments since last year. However, the Yampa Participation Agreement outlines that on or before June 1, 2011, any participant may elect to withdraw from the project. If any entity withdraws by June 1, the remaining owners have sixty days to make the same election. If entities elect to opt out, the remaining owners are required to take and pay for the additional capacity and associated costs. If everyone opts out, the project shuts down by 2014. It is unknown at this time if any of the participants will exercise this option, but a series of meetings are scheduled to begin discussions.

Board Member Comments. None.

Adjournment. With no further business, the meeting adjourned at 11:48 a.m. The next regular Board meeting is scheduled for Thursday, September 30, 2010, at 9:00 a.m. in the Platte River Power Authority boardroom, 2000 East Horsetooth Road, Fort Collins, Colorado.

AS WITNESS, I have executed my name as Assistant Secretary and have affixed the corporate seal of the Platte River Power Authority this 7 day of October, 2010.

Assistant Secretary