DRAFT

Keystone XL Pipeline Rate Impact Study

By

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The Keystone XL pipeline is proposed to be built to carry synthetic crude oil (syncrude), produced from the heavy bitumen mined at the tar sands project in Alberta, to markets in the US Gulf Coast. The pipeline would run from Hardesty, Alberta, to Texas. The line would run about 282 miles through Montana, entering the state from Alberta at a point approximately 39 miles NNW of Saco, and crossing into South Dakota at a point roughly 27 miles east of Ekalaka. The pipeline is designed to carry about 830,000 barrels[1] a day of crude oil, requiring electrically driven pump stations spaced periodically along the route. Six pump stations are proposed to be located in Montana. Service to these pump stations would be provided by local utilities – five by rural electric cooperatives and one by Montana Dakota Utilities (MDU).

Construction of the Keystone XL pipeline requires review and permitting under the Montana Major Facilities Siting Act (MFSA), administered by the Montana Department of Environmental Quality. Montana law[2] also requires that any facility covered by MFSA be the subject of a study of the rate impacts to Montana electric consumers, to be performed by the Montana Consumer Counsel. This report describes the results of that study.

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[1] The original design called for pumping volumes of 900,000 barrels per day. The pipeline sponsors notified the Montana DEQ on October 10, 2010, that this has been reduced to 830,000 barrels a day. It is not known whether the reduction in design capacity will affect pump station design or load but in any case a reduction in pump load will not result in increased risk of rate impacts.

[2] ***69-2-216. Customer fiscal impact analysis – requirements.*** *(1) Within 10 days of receiving an application pursuant to subsection (1)(a) or (1)(b), the department of environmental quality shall notify the office of consumer counsel that it is in receipt of:*

(a) a permit application pursuant to Title 75, chapter 2, 5, or 10, for a new electrical generation facility; or

(b) an application for a certificate under the Montana Major Facility Siting Act for a new facility or upgrade, as defined in 75-20-104.

(2) The office of consumer counsel shall complete an analysis outlining the fiscal impacts of the project on electricity customers in Montana. The analysis must include an estimation of how customers' rates may be impacted.

(3) (a) Except as provided in subsection (3)(b), the analysis must be completed within 30 days of receipt of the notice from the department.

(b) The department shall extend the 30-day deadline if compliance with the deadline is not necessary to comply with the requirements of subsection (4).

(4) The analysis must be provided to the department and incorporated into the department's environmental review, including draft documents released for public comment.

(5) (a) Within 5 days of the close of the public comment period for an application referred to in subsection (1)(a) or (1)(b), the department shall forward public comments related to the analysis to the consumer counsel.

(b) The consumer counsel shall respond to the comments and return the responses to the department within 30 days, and the responses must be included in the final environmental reviews.

The pipeline would serve no Montana customers other than possibly opening a new route for Montana oil producers to ship product to Gulf Coast markets. Since it would not sell electricity, there would be no direct impact on electricity consumers due to the construction and operation of the pipeline. However, service to the pump stations involves varying amounts of investment in new transmission lines and substations by the Montana electrical utilities providing service, and the electrical consumption of the pump stations may be a significant increase in the volume of electricity needed to be acquired and sold by them.

Table 1. Pump Station Locations, Electric Provider, and Transmission and Substation Construction Requirements[3]

Pump Station	Name	Provider	Transmission (miles)	Voltage	Transmission, substation cost
PS9	Phillips	Big Flat EC	62	115 kV	$20.6 million
PS10	Valley	NorVal EC	50	115 kV	$17.3 million
PS11	Fort Peck	NorVal EC	0	230 kV	$4.5 million
PS12	Circle	McCone EC	5	115 kV	$4.9 million
PS13	Prairie	Tongue River EC	15	115 Kv	$7.6 million
PS14	Fallon	MDU	5	115 kV	$4.9 million

It should be noted that Montana law exempts from the rate impact study requirement electrical transmission lines proposed by utilities that report to the Montana Public Service Commission or to FERC. If the electrical facilities required by the pipeline were simply freestanding projects to be built by the relevant utilities, no rate impact study would be required for them. Further, some or all of the transmission projects needed to serve the pump stations may be exempt from the requirements of MFSA either because of the length and voltage of the projects or because they come under a "75/75" exemption. However they are being studied here as possible sources of indirect impacts of Keystone, because they are solely or primarily intended to support the Keystone Pipeline and any impacts would be attributable to the construction of the pipeline.

The potential for impacts to the electrical customers of the utilities depends upon the costs to the utilities of providing service and the rates and other cost sharing and guarantee arrangements they negotiate with the pipeline. If the rates for service cover at least the incremental costs of service and the pipeline operates as planned, there should be no near term direct impact on rates. However, if the service is provided at current average cost of service rates while the incremental cost of power is greater than the current average cost, electric customers could see their rates go up as a result of service to the pipeline.

Further, the utilities will have to construct new facilities that will be dedicated to service to the pipeline, for example transmission lines to serve a remote pump station, or a substation to

[3] Source for pump station data in Tables 1-2: letter Brian Holland to Larry Nordell, Sept 15, 2010

provide voltage transformation and switching capability. If the utilities finance the costs of these facilities and expect to recover the costs over time through a capital component embedded in monthly rates per kWh or per kW, the utility and its customers could be at risk should the pipeline not be completed, shut down prematurely, or significantly scale back its shipments. While such eventualities may seem unlikely at present, energy markets are volatile and change in unpredictable ways, and future environmental regulations that might affect the tar sands project are impossible to predict[4]. Complete insulation of existing electrical customers from such risks would probably require specific financial arrangements such as up-front financing by the pipeline or posting of long-term bonds to guarantee repayment; even then some residual risk, such the risk of default by a bonding agency, might remain.

With regard to information sources used in preparing this report, the legislation that placed responsibility for this analysis on the Montana Consumer Counsel did not provide the MCC with the ability to require parties to answer questions or to provide data. Therefore this report is primarily based upon information voluntarily provided by Keystone, the three G&T coops (Central Montana G&T serves Big Flat and NorVal, Upper Missouri G&T supplies McCone, and Southern Montana G&T supplies Tongue River) that provide wholesale supply to the four coops to serve pump station loads, WAPA, MDU, and from the coops themselves. Some limited published data, for example from the Rural Utilities Service, the EIA, and from the Montana Electric Cooperatives' Association, was also of use.

This impact study focuses on the potential risk to ratepayers, and the actions that might protect them from rate impacts. Three potential sources of risk are addressed: the acquisition and resale of power to serve the pump stations; the financial commitment required to construct transmission and substation facilities to connect the pump stations to the grid; and the long term costs of adding new electric generating facilities to serve load growth. The study evaluates the situation of each of the suppliers, and their efforts to protect themselves and their ratepayers.

1. Power supply risk

Coop customers could be at risk if the costs of serving the pump stations exceed the average costs currently faced by the coops to supply their customers and the suppliers average all costs to set rates. The coops have the benefits of an allocation of relatively low cost power from Federal Missouri River hydro projects that meets part of their needs; averaging costs to set rates to the pump stations could result in diluting those benefits for existing customers. The magnitude of the pipeline load is significant, and if the full incremental costs are not recovered from the pipeline, customers could see their rates go up noticeably. On the other hand, if rates are properly designed to pass through the incremental power costs and to pick up a share of the coop overhead, existing customers could benefit from the presence of the pump station load. The coops are not regulated, and have the flexibility to set their own rates. On the other hand, MDU does not have that flexibility as it must serve customers under rates posted with and approved by

[4] Pump station power usage in Montana could also be reduced if large quantities of crude were to be shipped from points south of Montana to the Gulf Coast, reducing or displacing flows from Alberta.

the Montana Public Service Commission. Any modification of those existing, posted tariffs would require approval by the PSC.

Table 2. Pump size, Electrical Load, Electrical Use (all pumps 6500 hp)

Pump Station	Pumps	Peak Load	Average Load	Annual Energy[5]
PS9	2	9.6 MW	6.7 MW	58.7 million kWh
PS10	3	13.6 MW	9.5 MW	83.2 million kWh
PS11	3	13.6 MW	9.5 MW	83.2 million kWh
PS12	3	13.6 MW	9.5 MW	83.2 million kWh
PS13	3	13.6 MW	9.5 MW	83.2 million kWh
PS14	3	13.6 MW	9.5 MW	83.2 million kWh

Table 3. Pump station load vs current supplier load

Pump Station	Provider	PS Load (million kWh/yr	Provider MT Load[6]	% Increase
PS9	Big Flat EC	58.7 million	27.1 million	217%
PS10,11	NorVal EC	166.4 million	54.9 million	303%
PS12	McCone EC	83.2 million	64.9 million	128%
PS13	Tongue River EC	83.2 million	86.4 million	96%
PS14	MDU	83.2 million	700.4 million	12%

a. Big Flat and NorVal Electric Cooperatives

Two of the coops, Big Flat EC and NorVal EC, serving three pump stations, are supplied by the Central Montana Electric Power Cooperative (Central Montana). The pump stations will be very significant loads for the coops. For Big Flat EC, electric consumption by pump station 9 is more than twice the current total usage of all existing customers. Table 4 below indicates the current load of Big Flat is approximately 27 million kWh/year, while PS 9 is expected to use about 59 million kWh/year[7].

NorVal EC is about twice the size of Big Flat EC, with current sales at approximately 55 million kWh per year. The two pump stations that will be served by NorVal are larger than PS 9; PS 10 and PS 11 will each use about 83.2 million kWh per year, for a total load on NorVal of 166.4 million kWh. This is about three hundred percent of current sales.

[5] Assumes pipeline runs 8760 hours per year; should be adjusted for down time as there are no spare pumps
[6] Source: EIA.
[7] Note that the projected load at PS9 is 9.6 MW, while the load at each of the other pump stations in Montana is 13.6 MW. The pump stations and electric facilities to serve them are designed for an ultimate possible buildout to 22.7 MW, however the analysis below focuses on the initial construction levels because it was not know when or whether the ultimate buildout would take place. The conclusions remain basically the same.

Central Montana gets its supply mainly from three sources: the Western Area Power Administration (WAPA), the Basin Electric Power Cooperative (Basin), and an allocation from BPA which will expire in September, 2011. WAPA provides a fixed allocation of power from the upper Missouri Basin Pick-Sloan program dams operated by the US Bureau of Reclamation. This is preference power allocated to coops, municipalities and public agencies. It is relatively low cost power because it comes from older projects built by the Federal government and it is sold at cost, although the costs include a share of the costs of power delivered to irrigation projects. No new projects are planned, so the Pick-Sloan allocation will increasingly be supplemented as loads served by Central Montana grow.

Basin Electric Power Cooperative owns thermal plants and some renewable plants. Basin is in the position of being the marginal supplier that serves load growth for its customers, and builds new generation as needed.

Central Montana has adopted a policy of melding its Pick Sloan and BPA allocations with power from Basin Electric to serve the residential and farm loads of the coops it serves. However, all large loads of 3 MW or higher are separately metered and billed, and are served solely with power from Basin Electric. For current customers of Big Flat and NorVal, this means that the benefits they receive of Pick-Sloan power (BPA power will not be available after September 2011) will not be adversely affected by service to the Keystone XL pump stations, because those pump stations will pay a rate that includes the full cost of power from Basin Electric charged to Central Montana (which will include a share of Central Montana's overhead costs) billed to the coops, and passed through to Keystone with a share of the coops' overhead costs. There should be no direct impact to existing customer rates for Big Flat and NorVal due to supplying power to the pump stations[8].

b. McCone Electric Cooperative

McCone EC is about 20 percent larger than NorVal, with current sales of about 65 million kWh per year. Pump station 12, to be served by McCone, is the same size as PS 10 and PS 11, and will use about 83.2 million kWh per year, roughly 130 percent of current sales.

McCone EC is supplied by the Upper Missouri Generation and Transmission Electric Cooperative and the Central Montana Electric Power Cooperative. However, Central Montana serves only one delivery point for McCone, at Mosby, so power for PS 12 will come from Upper Missouri. Like Central Montana, Upper Missouri has a fixed allocation of Pick-Sloan power from WAPA, and the remainder of its needs is provided by Basin Electric[9].

Upper Missouri does not socialize the Pick-Sloan allocations of its members; each retains the allocation it was originally given and the WAPA power is passed through to the coops at cost. Similarly, power from Basin Electric is passed through to the coops at cost, although the rates may be specific to particular end users. Upper Missouri's overheads are not billed at a kWh rate but are charged directly to the coops. Power for PS 12 will be metered directly by Upper

[8] Personal communications from Doug Hardy, Central Montana; Jeanne Bernard, Big Flat EC; Craig Herbert, NorVal E.C., and Dave Raatz, Basin Electric Power Cooperative.

[9] Personal communications, Mike Kays, McCone E.C., and Dave Raatz, Basin Electric.

Missouri, supplied to Upper Missouri by Basin at Basin's large pumping rate, and passed through to McCone at the same rate. McCone will pass that rate through to Keystone with appropriate overheads added. McCone's customers should see no dilution of the benefit they receive from Pick-Sloan power, and there should be no direct impact on their rates due to McCone's service to PS 12.

c. Tongue River Electric Cooperative

Tongue River EC is the largest of the four eastern Montana electric cooperatives serving the pipeline. Tongue River EC has current sales of approximately 87 million kWh per year. Pump station 13, to be served by Tongue River, is the same size as PS 10, 11 and 12, and would use about 83.2 million kWh per year, which is about 96 percent of current loads.

Tongue River EC is supplied by the Southern Montana Electric Generation and Transmission Cooperative. Southern Montana receives a fixed allocation of preference power from the Pick-Sloan projects through WAPA. Southern Montana also has a small allocation of Federal preference power from the Bonneville Power Administration that expires next year. Southern Montana does not belong to Basin Electric Power Cooperative; rather it buys power to serve the needs of its members (beyond the fixed preference power allocation) from the market, including PPL Energy Plus. Southern Montana will purchase power to serve Pump Station 13 from a market participant in the Eastern Interconnection of the national electric grid.[10] The costs of this purchase, plus the associated transmission costs to deliver the power to PS 13, (plus a share of Southern Montana overhead costs) will be directly billed to Tongue River and passed through to Keystone[11]. As with the loads served by Central Montana, this ensures that Keystone pays at least the incremental costs of service and that Southern Montana retains the full benefits of the Pick-Sloan preference power for its members' existing residential and farm load.

d. Montana Dakota Utilities

Finally, MDU would provide service to PS 14. MDU is much larger than the coops, with current sales in Montana of about 700 million kWh per year. The pump station load is only about 12 percent of current sales. Consequently, an underrecovery would have a much smaller impact on existing customers.

MDU is in a somewhat different position than the coops, since it will be selling power to Keystone XL pipeline at a tariffed rate, the Large General Electric Service Rate 30, filed with the Montana Public Service Commission[12]. Following is a summary of the current rate, filed October 1, 2009:

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[10] The high voltage AC transmission network of the US and Canada consists of five separate grids, (the Western Interconnection, the Eastern Interconnection, Texas, Alaska, and Quebec) which are not synchronized with each other and which can only be connected for purposes of transferring power with expensive AC-DC-AC converter stations. The boundary between the Eastern and Western Interconnections passes through eastern Montana, where there is a converter station at Miles City. PS 13 is located on the eastern side of the system break and its power supply must come from the Eastern Interconnection.

[11] Personal communications, Alan See, Tongue River E.C., and Tim Gregori, Southern MontanaE.G.&T.

[12] Personal communication, Tammy Aberle, MDU.

Base Rate:	$25.00 per month	
Primary Service:		
Demand Charge:	October-May	$5.15 per KW
	June-September	$6.15 per KW
Energy Charge		
	October-May	3.565¢ per KWh
	June-September	5.445¢ per KWh

These rates are subject to periodic change as MDU files new rates and the Montana PSC approves them. At the current rates, Keystone XL would pay approximately $4.4 million per year for electric power (not counting recovery of transmission and substation investments discussed below). This is equivalent to an average rate of approximately 5.3¢ per kWh[13]. The rate can be expected to go up as MDU's costs go up in the future.

MDU indicates that this is adequate to cover the incremental cost of service to the pump station, although the Public Service Commission rate setting process focuses on just and reasonable rates based on actual and measurable costs, and is intended to cover actual average costs, not incremental costs. There is no basis for estimating a near term rate impact to MDU's existing customers on the basis of this charge (however see further discussion below on MDU's recovery of transmission and substation investments).

2. Transmission and substation investment risk

The second type of risk that could be imposed upon existing electric customers is associated with the need to construct varying amounts of new transmission lines and new substations to serve the pump stations. Table 2 summarizes the investment needed to serve each of the pump stations in Montana. The wide variation is due to the location of each substation in relation to the nearest location it can be reasonably served from on the existing transmission grid. Table 4 summarizes the new investment required for each of the electrical suppliers. For comparison purposes the current plant in service for each supplier is shown. As can be seen from Table 4, the required investment is significant, and would be a very large investment for Big Flat and NorVal, given the current size of the coops. To serve Pump Station 9, Big Flat must build 62 miles of new 115 kV line, plus a substation facility, at an estimated cost of $20.6 million. By comparison, the value of Big Flat Electric Coop's current plant in service is approximately $18 million. The new facilities will cost 114 percent of Big Flat's total current investment in plant. Similarly, PS10 will require a significant investment by NorVal. (PS11, also to be served by NorVal, is located adjacent to a point on the grid where it can be served from and will require only substation equipment – transformation and switching.) PS10 will require the construction of 50 miles of new 115 kV transmission line, plus substation equipment, at a cost of $17.3 million. Total investment required for NorVal for the two pump stations it will serve is estimated at $21.8 million. By comparison, the current plant in service for NorVal is $29.2 million. Service to the two pump stations requires an investment of about 75 percent of NorVal's total current plant.

[13] MCC calculation, assumes monthly usage of 6.933 million kWh; annual usage 83.2 million kWh; monthly demand of 13.6 MW.

The other suppliers do not face as big a burden relative to their current size. To serve PS 12, McCone Electric Coop will have to build 5 miles of new transmission, plus substation facilities, at a cost of $4.9 million, about 17 percent of its current plant of $28.7 million. To serve PS13, Tongue River EC will have to build 15 miles of new transmission, plus substation facilities, at a cost of $7.6 million, about a quarter the size of its current plant of $29.6 million. To serve PS14, MDU will have to build 5 miles of new transmission, plus substation facilities, at a cost of $4.9 million (Keystone estimate; MDU estimates $3.3 million[14]), under 3 percent of its current Montana plant in service total of $189 million.

Customers could be at significant risk with these investments, particularly customers of Big Flat and Norval, but also those of McCone and Tongue River, and to a much lesser degree, MDU, if the utilities invest in the facilities and for some reason are unable to recover their costs from Keystone. For example, if cost recovery is based on a long amortization period and insufficient guarantees or security is not in place, the supplier and its existing customers could be at risk if the project is never completed, or if the project is completed but shuts down prematurely, or if recovery is predicated on the expected volume of power use and the pipeline does not run at projected levels.

The suppliers recognize this risk and are taking a variety of approaches to protect themselves and their customers.

Table 4. New Facility Investment Requirements vs. Current Supplier Plant in Service

Pump Station	Provider	New Facility Investment Need	Provider Plant in Service[15]	% Increase
PS9	Big Flat EC	$20.6	$18.0	114%
PS10, 11	NorVal EC	$21.8[16]	$29.2	75%
PS12	McCone EC	$4.9	$28.7	17%
PS13	Tongue River EC	$7.6	$29.6	26%
PS14	MDU	$4.9	$189.0	3%

a. Big Flat

Big Flat EC's transmission project includes shared facilities, that will be used to serve some of Big Flat's customers as well as the pump station, for the first 33 miles, for which costs will be shared proportional to demand; the remainder of the line will be a dedicated facility billed entirely to Keystone, through a facility charge with provisions to prevent stranding. As part of the shared facility, Big Flat will also build a substation to serve existing customers who are

[14] MDU provided a construction cost estimate of $3.3 million for facilities to serve PS14 in 2008. This number should be adjusted for inflation to the date of construction, which is not known. Keystone has estimated the cost of the electrical supply facilities needed for PS14 at $4.9 million, but the date of the estimate is not known.

[15] Source: USDA Rural Utilities Service, 2008 Statistical Report, Rural Electric Borrowers

[16] Total for pump stations 10 and 11.

currently served by an obsolete substation far from their load, which will be retired. Shared facilities will be prorated by load according to the maximum possible ultimate buildout of the pump station (22 MW) and the area load (4 MW). Preconstruction expenses are being paid up front by Keystone under a letter agreement. Once a construction contract is signed by Keystone, Big Flat will finance the project through National Rural Utilities Cooperative Finance Corporation. Costs will be recovered and the loan repaid through monthly capital expense charges to Keystone. Provisions in both construction and operating contracts provide for guarantees from TransCanada, the corporate parent of Keystone XL, to ensure Big Flat will recover all stranded costs due to non-completion or premature shutdown. A separate monthly capital expense charge should eliminate any risk associated with reduction of throughput[17].

b. NorVal

Like Big Flat, NorVal intends to finance the investments in transmission and substation facilities required to serve PS10 and PS11 through CoBank of Colorado, and to recover the costs through monthly charges that cover the loan repayments. Security arrangements with TransCanada will ensure the loan is repaid without risk to other NorVal members, in the form of a Letter of Credit, with a provision for a balloon payment in the event of a premature shutdown of the pipeline[18].

c. McCone

McCone EC has arranged to have Keystone provide quarterly contributions of construction funds as the required transmission and substation facilities are built. In this way McCone will have no funds of its own or its members invested in the facilities to serve PS 12, and will bear no risk from them.

McCone also notes that WAPA will have pump station related investment costs of $3.14 million, which will be prorated and charged to the pipeline owners if service is discontinued within 17 years[19].

d. Tongue River

Tongue River will finance the transmission and substation investments required to serve PS 13 by borrowing from either the Cooperative Finance Corporation or CoBank. They will bill Keystone with a flat monthly capital recovery charge sufficient to pay off the loan over a term yet to be determined in the range of 8 to 15 years. Keystone will also provide an irrevocable letter of credit or letter of guarantee, from a bank with a credit rating acceptable to the coop's bankers, to ensure against any risk from premature shut down of the pipeline before the loan is paid off[20].

e. MDU

[17] Jeanne Bernard, op.cit.
[18] Craig Herbert, op.cit.
[19] Mike Kays, op.cit
[20] Alan See, op.cit.

MDU is bound by its line extension policy (Extension Policy Rate 112), approved by the Public Service Commission, which states that "a permanent extension may be constructed without a contribution if the estimated project construction cost is equal to or less than two times the estimated annual revenue." Projected power use by pump station 14 meets this test. MDU states that the rate for power sales to Keystone (see discussion above) includes a fixed cost margin that for a new load provides a margin which, if the test is met, is sufficient to recover the investment required to serve the load. MDU has used this methodology successfully with extensions to serve new large loads previously and is satisfied that it ensures there is no impact to other customers.

MDU will require TransCanada to carry a letter of credit for 5 years, rated at the full amount of MDU's transmission and substation investment cost for the first three years, with a reduction by one-third for each of the remaining two years if load projections are met[21].

3. Long Term Power Cost Impact Risk

The above discussion focuses on the near term risk to existing utility customers due to the provision of service by specific Montana electric suppliers to the Keystone XL pipeline pump stations. Over the long run, as loads grow, all power suppliers with a responsibility to serve customers eventually need to add new sources of supply to satisfy the growing loads. These new sources of supply can be new generating plants or they can be market purchases. Because inflation seems to be intrinsic to the US and world economies, it is often thought that new generating plants typically cost more than older plants, and adding new plants to a utility portfolio tends to drive up the cost of power. This would imply that load growth will tend to result in increased costs, and it has been suggested that addition of a new large block load, like the pumping load of the Keystone XL pipeline, will have a similar effect. This is a generalization, of course. If prices for the fuel to run an older plant go up sufficiently, construction of a new plant using a cheaper fuel may result in costs going down. Generating plants that burned diesel were retired after the petroleum crises of the 1970s and replaced with coal or natural gas fueled plants. In recent years most new thermal generating plants have been gas-fired, although now there is a significant push for environmental reasons to rely more on renewable generation. In the northern Great Plains, wind generation is the renewable technology of choice.

The common assumption among energy observers that new power plants are generally more expensive than old ones, is consistent with industry experience from the 1960s through the 1990s, when most new plants were nuclear or coal plants, but it has not always been the case and it may or may not be true in the future. From the earliest days of the utility industry until the 1960s, rates declined significantly as engineering improvements and higher pressures, together with increasing generating plant size, continually increased the efficiency and reduced the heat rate of coal plants, and as technology change reduced the cost of mining coal. During this period each new generation of power plant was larger, more efficient, and cheaper than the last. After about 1960 these improvements ceased to dominate the industry, and large, expensive coal plants and nuclear plants drove up power costs with each new plant. However, since the late 1980s

[21] Tammy Aberle, op.cit.

new generation has mostly relied on natural gas, with increasing use of wind, and while power plant costs remain subject to cost inflation, they may not automatically drive up rates. Current industry expectations are that natural gas will remain in relatively plentiful supply, while wind costs, particularly the costs of regulating wind, are uncertain but potentially subject to a learning curve. Environmental costs and regulation may drive up the costs of power from existing coal plants. These factors could lead to an environment where new plant costs could reduce average costs.

An increase in load growth does advance the date at which new plants are needed, and the Keystone pump station loads, like all growth, will likely have that effect. While pricing arrangements like those used by the coops can protect against dilution of the benefits they receive from the Pick Sloan project, they cannot protect against an increase in the costs of Basin Electric Coop's portfolio if Basin has to add new plants that drive up power costs. MDU customers are in a similar position. Basin and MDU will do the best they can, within the relevant framework of environmental and RPS regulations, to ensure they pick the best resources as they expand.

On the other hand, if there is an offsetting decline in loads, either through the loss of existing large industrial loads or simply due to unfavorable economic conditions, planned new generating plants may be put on the shelf and plants with expensive operating costs may not run as often. On balance, it may not be possible to discern in advance whether, how much, and possibly even in what direction load growth will affect rates.

a. MDU

MDU's last resource plan, completed and filed with the Montana PSC in 2009, was predicated on a resource plan that included the projected load of PS14[22]. That forecast showed projected summer peak loads of about 531 MW in 2012, including 13.6 MW for PS14. Taking out that load would reduce forecasts by 13.6 MW, to something over 517 MW in 2012, 529 MW in 2013, and 542.5 MW in 2014. Thus addition of the pipeline load advances projected load growth by a little over one year. The resource plan indicates a need to add resources to meet loads and reserve requirements. The chosen resource plan called for additional capacity purchases for the period 2011 through 2014, adding around 130 MW of baseload power from a share in the planned Big Stone II plant by 2015, a 75 MW natural gas fired combustion turbine in 2015, and a second 75 MW combustion turbine in 2021. It also called for an additional 15 MW of demand side resources and interruptible load by 2015, and a wind farm, the Cedar Hills project, 19.5 MW to come on line in 2010. (The Big Stone II plant was abandoned in November 2009, and MDU indicated it would issue an RFP for capacity and energy purchases to begin in 2015.[23] These dates are likely to be subject to change as the target dates approach, due to the uncertainty over future load growth and resource availability and the normal practice in turning resource plans into decisions to begin construction. Further, MDU's need for new resources is significantly affected by its reserve requirement. Historically, the reserve requirement has been 15 percent, and this is a major driver in MDU's resource planning. The Midwest Independent System

[22] Montana-Dakota Utilities Co. 2009 Integrated Resource Plan, submitted to the Montana Public Service Commission September 15, 2009. Docket N2009.9.122

[23] MDU response to PSC-001 in MPSC docket N2009.9.122.

Operator (MISO) is currently considering a change in reserve requirements that could have the effect of reducing MDU's need for reserves; this would defer the need for new resources to come on line. It is possible that the presence or absence of the Keystone load could change the dates that new resources would be added, although given the size of contracts that are expiring in 2014, as well as the uncertainty over load growth and possible loss of existing loads, it is unlikely that there would be any significant advancing of the date at which new resources come on line.

When and if PS14 is expanded to its ultimate level of 22.7 MW (an increase of 9.1 MW) a similar analysis would show the possible advancing of construction of planned resources by up to a year.

b. Basin Electric

Basin Electric will provide the power needed to serve pump stations 9, 10, 11 and 12 in Montana. Power to serve PS13 will be provided through a market purchase by Southern Montana G&T from an unknown source, and PS14 will be provided by MDU. The cumulative power requirements faced by Basin to serve the four Montana substations would be about 50 MW, and at ultimate buildout, up to 84-91 MW. However, this is not the end of Basin's responsibility for service to the Keystone XL pipeline, and there are seven pump stations in South Dakota that will be served by coops that are Basin member systems. If all these are also served with power from Basin, then Basin's initial responsibility could be as high as 145 MW, and at ultimate buildout, as high as 243-250 MW.

Basin is a large system that serves member systems in Montana, North Dakota, South Dakota, Wyoming, Colorado and Nebraska. Basin has existing fossil generation plants with capacity totaling 3,048 MW, and existing renewable generation with total nameplate capacity of 501 MW. It has committed plants under construction or permitted totaling 940 MW, including the Dry Fork Station coal plant rated at 422 MW gross, or 365 MW net (about to be completed); the Deer Creek Station gas-fired combined cycle plant rated at 300 MW (net), scheduled to come on line in 2011; the Prairie Winds SD1 project, a 151 MW wind farm recently passed environmental permitting review by the Rural Utilities Service and WAPA, currently in the financing stage; the South Dakota Wind Partners project, an additional 15 MW wind project that would connect with and share facilities with the SD1 project[24].

The initial loads of the Keystone pump stations served by Basin could be as high as 4.8 percent of its thermal generation capability or 4.1 percent of total generation. The presence of the pump stations could lead Basin to move up by one year the targeted online date of planned new resources; an expansion to the full buildout of the pump stations at some future date could have a similar effect. However, because of the uncertainty in load growth as well as the uncertainty in the construction time and completion date of large generating resources it may not be possible to distinguish any change in the need for and on line dates of new resources.

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[24] Information from Basin Electric web site
http://www.basinelectric.com/About_Us/Corporate/At_a_Glance/index.html , and from Dave Raatz, op.cit.

Conclusions

Service to the Keystone pump stations represents a significant increase in load, as well as a significant investment compared with current plant in service, for each of the four Montana electric coops that will serve them. However, the coops, and their suppliers, are well aware of that fact and have taken careful measures to insulate themselves and their customers from the risk of cost increases due to taking on such sizeable loads. By setting up pass-through rates for wholesale power from Basin Electric, and by security measures to ensure payment of the costs of new transmission and substation investments (and in the case of McCone, by arranging for up front payment of electric facility construction costs by Keystone) the coops appear to have done a good job of eliminating the risk of cost increases due to service to the pipeline, construction of the electrical infrastructure, or from early termination of pipeline and pump station operation.

Service to the Keystone Pump Station 14 by MDU does not represent as significant an increase in proportion to existing load as it does for the coops, rather in the order of 12 percent of Montana loads, and the required facility investment is roughly 3 percent of Montana plant in service. Nevertheless, MDU has proceeded in a way that it believes will protect its existing customers from any direct rate impacts from service to the pipeline. It will recover its infrastructure costs through the fixed cost margin on power sales, and will require an irrevocable letter of credit to ensure the revenue flow continues at least long enough to fully recover those costs. Should any unexpected risks emerge, the Montana PSC will have tools at its disposal to protect MDU's other customers, for example by directing MDU to create a separate rate class to recover costs directly from the pipeline. While it has never been done in Montana, in the event of a shutdown the PSC may be able to require a write-off of any incomplete cost recovery of special purpose facilities built to serve the pipeline.

There could be some long term impacts to the resource portfolio plans of Basin Electric and of MDU, in the form of a need to advance the dates at which new resources are planned to come on line. However, given the size of the pump station loads served relative to the resource portfolios and planned new resources of Basin and MDU, and given the normal uncertainties over load growth and the cost and completion dates of planned facilities, any such impacts should be minor and in fact may not be distinguishable.