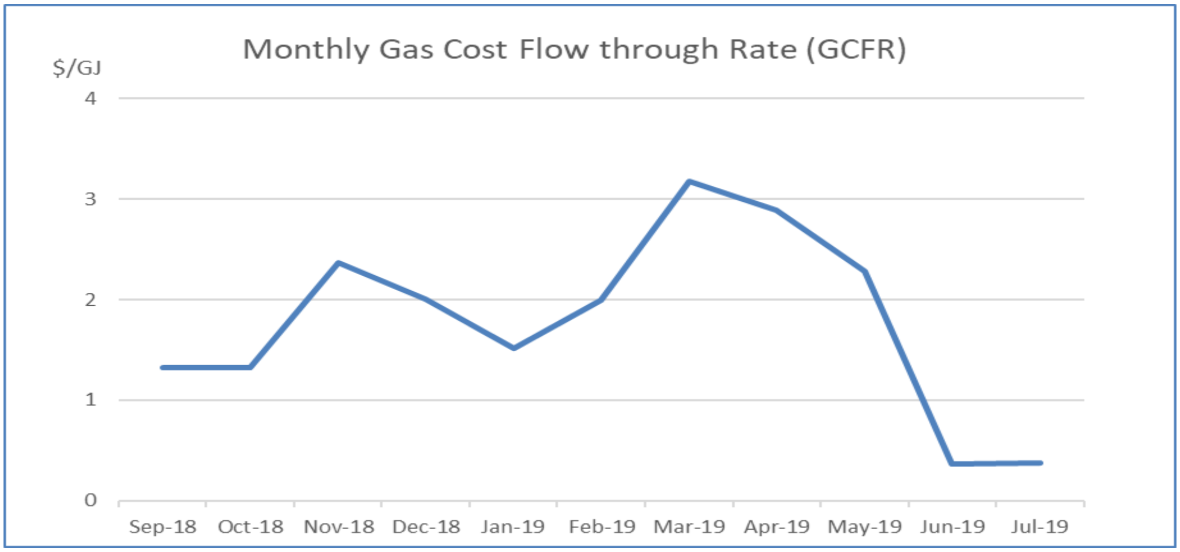
ENERGY PRICES AND MARKETS

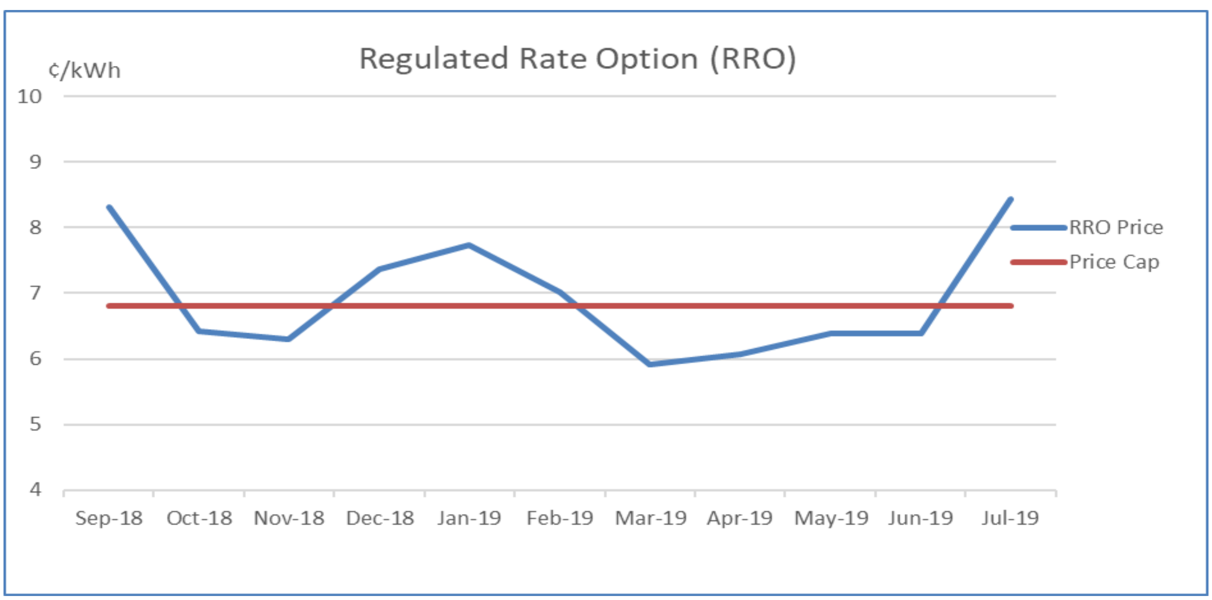
Natural Gas

The 2019 July gas cost flow-through rate (GCFR) was $0.37 per gigajoule. Natural gas market prices are forecast to remain below a dollar until the fall heating season begins. For the week ending July 1, the Alberta daily price averaged $0.69 per gigajoule. Natural gas costs for The City thus far in 2019 are up 7.2% (roughly $392,000) relative to 2018 due to increased unit cost.



Electricity

The ENMAX regulated rate option (RRO) in 2019 July was 8.43 cents per kilowatt hour ($84.34 per megawatt hour). The Price Cap of 6.8 cents per kilowatt-hour will be in effect for July 2019. Electricity costs for The City thus far in 2019 are up 7.8% (roughly $2.6M) relative to 2018 due to increased unit cost.



The month-to-date all-hours average price for 2019 June was 5.35 cents per kilowatt-hour. For reference, the month-to-date all-hours average price for 2018 June averaged 6.34 cents per kilowatt-hour. Low natural gas prices and a lack of scheduled outages should keep power prices from rising too high.

Oil Price Spread

The Notice of Motion, Standing Up for Canada's Responsible Energy Industry (C2018-1448), discussed at the 2018 December 17 regular meeting of Council, directed Administration to develop a strategy for The City to advocate for improved market access on behalf of Canada's responsible energy industry. Intergovernmental and Corporate Strategy prepared a report on this matter for the March IGA Committee meeting. Subsequently, Administration was directed in IGA2019-0255 to pursue ongoing monitoring of the oil price discount for Western Canada Select (WCS) relative to West Texas Intermediate (WTI) and to report on progress toward improved market access.

The differential between WCS and WTI is due to several factors. The primary ones are:
- increased production by Canadian energy companies;
- limited pipeline capacity to ship WCS to the United States market; and
- a lack of access to international markets other than the United States.

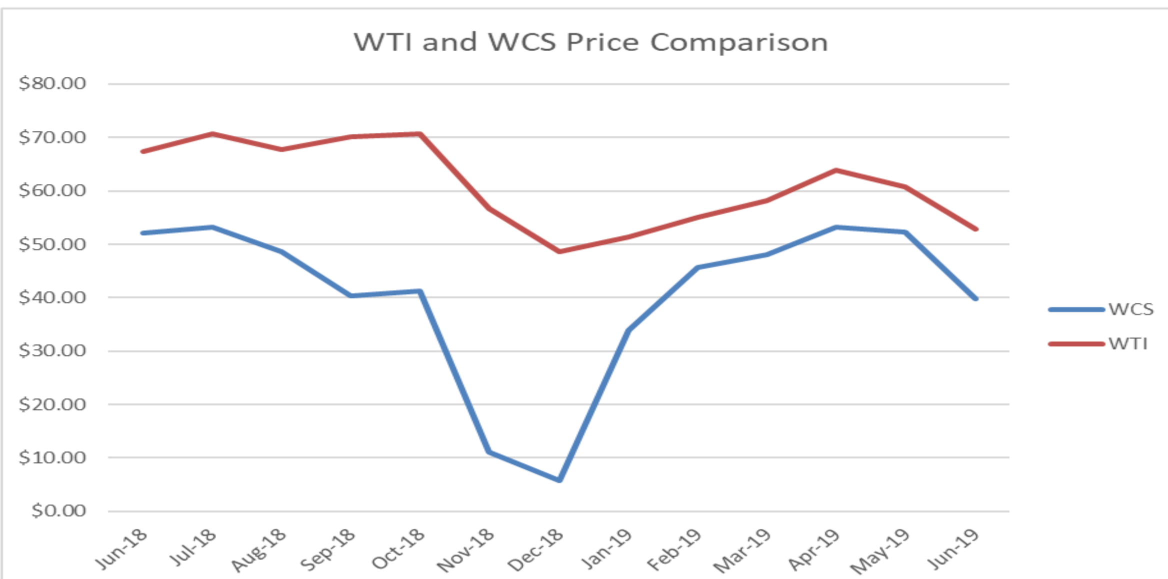
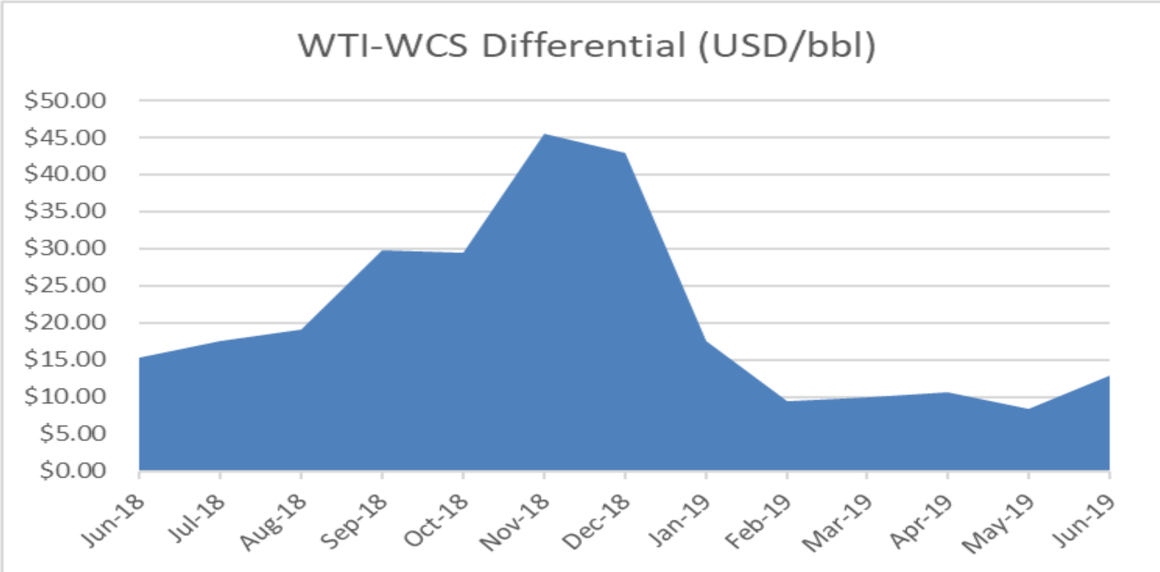


*Chart data from www.gljpc.com/price-charts
**WTI and WCS monthly prices are set based on the weighted average of all trades that occur in that month.

The Government of Alberta has estimated that with the record-setting price differential (U.S. $55 on 2018 October 12), the lost revenue to oil producers was between $80 and $100 million a day at the peak. The price differential has narrowed, due primarily to Government of Alberta policy. The Government of Alberta introduced an oil curtailment program on 2019 January 1.



The oil curtailments have been ratcheted down in tranches in 2019. Table 1 below summarizes the oil curtailment levels that have been in effect thus far in 2019. The Alberta Government is planning to scale back the curtailment in 2019 August by 25,000 barrels to a total of 3.74 million barrels per day. The Oil curtailments are scheduled to end on 2019 December 31.

Table 1

	January 2019	**February 2019**	**April 2019**	**May 2019**	**June 2019**
Mandated reduction due to Curtailment Policy (barrels per day)	325,000	250,000	225,000	200,000	175,000
Effective Production Limit (barrels per day)	3,560,000	3,635,000	3,660,000	3,685,000	3,710,000

UTILITY REGULATION

Carbon Tax Changes

On 2019 June 4, Bill 1 the *Carbon Tax Repeal Act* received Royal Assent. This Bill ended the tax the previous government imposed on a variety of fuels effective 12:01 a.m. on 2019 May 30. The Alberta government has estimated that the average small business will save $4,500 annually and Alberta families will save $1,150 per year.

The carbon tax costs are embedded in the price of associated fuels (diesel, gasoline, natural gas, etcetera) and the direct costs to The City in 2018 were estimated to be $6.4 million. There are also indirect financial impacts of the carbon tax to the City through other expenditure spending which is difficult to quantify because the carbon tax impact is embedded into the cost of goods and services. While the elimination of the carbon tax on its own would be expected to reduce the price of these fuels, the volatile nature of these prices as a result of other market factors makes it impossible to predict the financial impact at this point. Table 2 below provides the actual 2018 total spent by The City on Carbon Taxes.

Table 2

Type	Unit	Alberta Rate ($ per unit)	2018 City Carbon Tax Amounts ($)
Aviation turbo fuel	litre	0.0775	$21,231.46
Gasoline	litre	0.0673	$630,396.03
Diesel	litre	0.0803	$2,673,803.98
Methanol	litre	0.0326	$3.06
Propane	litre	0.0462	$11,614.72
Natural Gas	cubic metre	0.0406	$3,015,710.01
CNG	cubic metre	0.0458	$4,446.80
Total			**$6,357,206.06**

On 2019 June 13, the Federal Environment Minister advised that the federal government carbon tax will be imposed on Alberta starting 2020 January 1. If implemented, the federal carbon tax would partially offset the savings to The City in 2020. Staff will develop a estimate of the federal carbon tax costs closer to its implementation date.

On 2019 May 3, the Saskatchewan Court of Appeal ruled in a 3-2 decision that the federal government has the constitutional authority to impose a federal carbon tax when there is no provincial carbon tax or when it is below the federal carbon tax. The ruling indicated that the Constitution states that Parliament can pass laws in the name of peace, order and good government. Saskatchewan's Premier Scott Moe conveyed his disappointment and indicated that the province would explore an appeal of the decision with the Supreme Court of Canada.

On 2019 July 2, Ontario's Court of Appeal ruled in a 4-1 decision that the federal carbon tax is constitutional.

Earlier this year, the Alberta Premier Jason Kenny said that if Ottawa were to impose a carbon tax, the Government of Alberta would join Saskatchewan and Ontario governments and seek a constitutional challenge of the tax through the courts.

Capacity Market

On 2019 June 14, the Alberta Energy Minister announced that the 90-day review of Alberta's electricity market system had begun. Over the next few weeks, the Minister will be meeting with stakeholders to determine the best path forward to attract new investment, maintain affordable electricity prices for and preserve our high standards in electricity reliability.

Industry support for the capacity market transition has weakened due to the following factors;

- Policy: The rapid pace of growth for renewable energy options will no longer be through government mandated policy.

- Costs: Electricity consumers are expected to pay much higher prices. Large consumers will also face more complex operational decisions.
- Financing: Financing projects will not be easy. Banks have indicated that the current capacity market proposal is not financeable, and equity investors want higher returns given the additional risks and complexity of a new market.
- Apathy: General frustration over the amount of government and market agency intervention that is likely to be involved over the coming years.

Coal to Gas Conversions

Historically, coal met approximately 70% of the total Alberta electricity demand. It was due to an abundance of coal deposits, which made low-cost mine-mouth coal-fired generation the dominant source of base-load electricity. Power generation units would typically run around the clock, at or near full capacity, except when they were unavailable as a result of outages.

Under the previous Alberta NDP government, the plan was to achieve renewable energy growth through a direct policy mandate. Coal-fired capacity received an accelerated retirement schedule for the end of 2030. The government established the Carbon Competitiveness Incentive Regulation ("CCIR"), expected higher carbon costs in the future, and the move to a capacity market was guaranteed.

Under the current Alberta UCP government, the plan is to achieve renewable energy growth through market-based means, just as it was until 2015. Coal-fired capacity is likely to remain on the accelerated retirement schedule. One rationale for this view is alignment with the Federal government's recently communicated plan to retire all coal-fired generation by 2029. As well, the Off-Coal agreements have been in place for over two years. CCIR will transition to Technology Innovation and Emissions Reduction ("TIER"). The objective is to have lower carbon compliance costs, with the cost of carbon to drop to $20 per tonne. The ability of the provincial government to implement TIER could be affected if the courts determine that the federal government has over-arching authority to set the price of carbon.

A result of this change to TIER has been to make the production of electricity using coal decidedly economically viable once again. The chart below illustrates that under TIER (the blue line), the marginal cost of a coal plant would be expected to be roughly 40% lower than that of a converted unit under CCIR (the black line).

Projected Marginal Cost of Coal vs Coal-to-Gas (NDP CCIR vs UCP Tier)

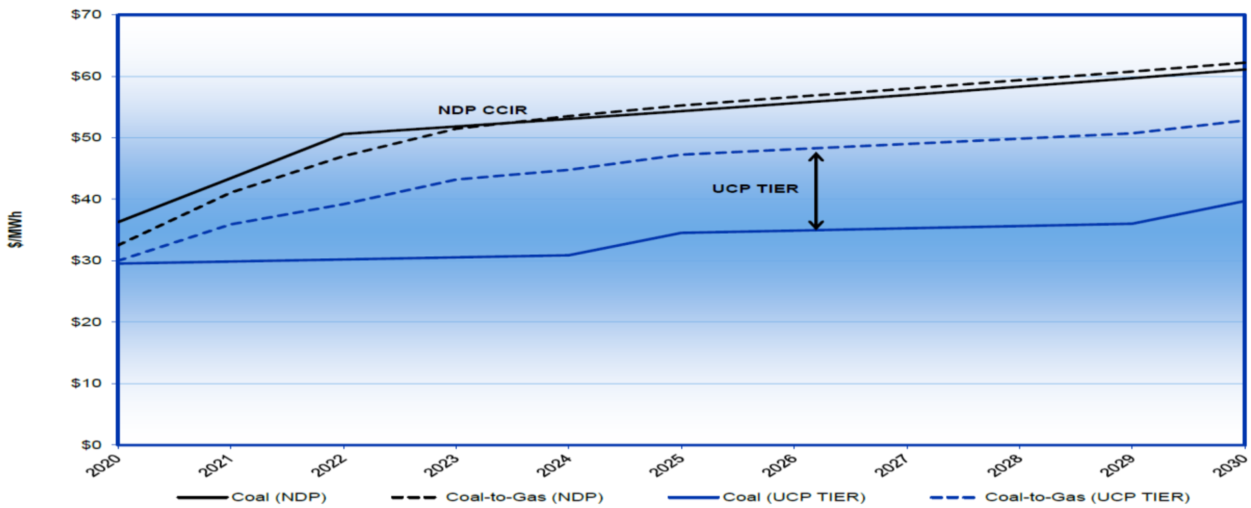


*Chart from EDC Associates Q2-2019 Forecast Update

It is unlikely generators will continue to pursue coal to gas conversions until the federal vis-à-vis provincial carbon tax matter gets resolved. Coal currently makes up about 30% of Alberta generating capacity. The AUC has approved four coal to gas conversion projects expected to add about 4,000 MW in capacity. The fifth coal to gas conversion project with projected 1,266MW in capacity is under regulatory review. As none of the planned coal to gas conversion projects have begun construction, project economics would suggest there may be no rush by generators to move off coal.

Trans-Mountain Pipeline Approval

The Canadian Federal government first approved the Trans Mountain expansion project in 2016. The approval was later overturned by a court decision, which found that the federal environmental review was flawed, and that the federal government had failed to adequately consult First Nations affected by the project, as required under the Constitution.

In response to the court decision, the Federal government recently released a detailed report outlining its efforts to accommodate affected First Nations, as well as outlining new conditions in addition to the 156 conditions recommended by the National Energy Board.

On 2019 June 18, the Federal government approved the Trans-Mountain pipeline expansion for the second time. The government accepted all of the 156 conditions and amended six of them to include strengthened marine and emergency response plans with far more Indigenous participation. Canada Development and Investment Corporation (CDEV), a Crown Corporation, is the current owner of the pipeline expansion project.

If completed, the Trans Mountain pipeline expansion project would triple the capacity of an existing pipeline system, allowing it to transport up to 890,000 barrels per day of bitumen and other petroleum products from Alberta's oil patch, to a marine terminal in Burnaby, British Columbia. It would effectively require the construction of a new pipeline along a slightly modified route.

The pipeline expansion means Trans Mountain will need new permits, authorizations and other approvals under various statutes, such as the Fisheries Act, the Species at Risk Act, and the Indian Act. Government officials indicated on 2019 June 18, that they expected CDEV to release a new cost estimate for the project after it takes stock of the new regulatory process.

The CEO of the CDEV believes construction should resume in September 2019 with Alberta oil ready for delivery to the west coast by mid-2022. The province of British Columbia has vowed to renew its legal challenges to the pipeline expansion project.