yukon energy

2021 annual report

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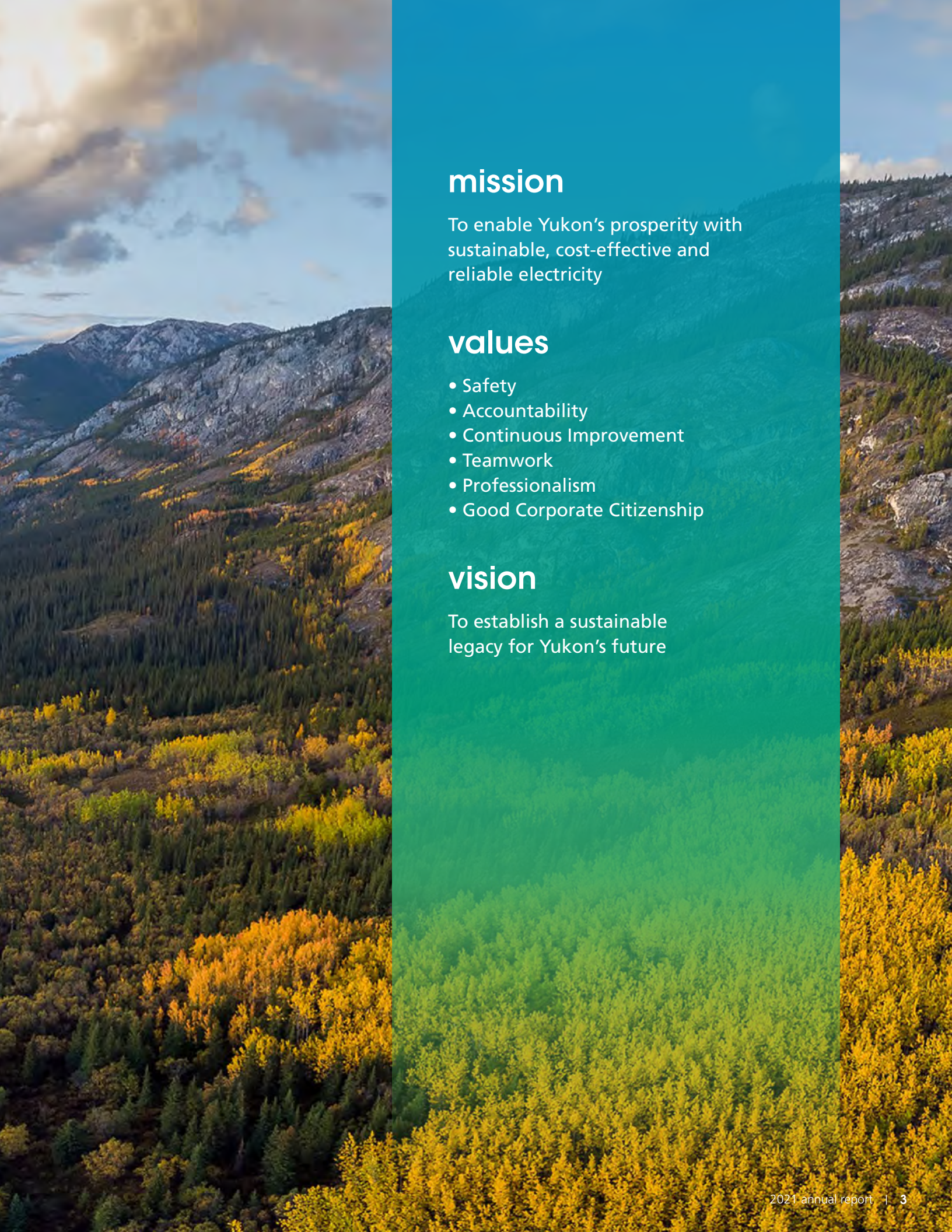
who we are

Yukon Energy is a publicly owned electrical utility established in 1987. We operate as a business, at arms-length from the Yukon government, to generate and transmit electrical energy in Yukon. We work with Yukon Development Corporation, our parent company, to provide sustainable, cost-effective and reliable electricity to Yukoners.

There are over 21,000 electricity consumers in the territory. We provide power to most of them indirectly, through ATCO Electric Yukon, who buys wholesale power from us. We directly serve some 2,200 residential and business customers, most of whom live in and around Dawson City, Mayo and Faro, and three industrial customers across the territory.

Most of the electricity we produce is renewable, coming primarily from hydro resources at our Whitehorse, Aishihik and Mayo hydroelectric facilities. We also generate a small amount of thermal energy from our liquefied natural gas (LNG) and diesel plants. These thermal plants ensure we have reliable electricity when it's needed at peak times, during emergencies and when renewable sources of electricity are not available.

Our headquarters are located near the Whitehorse Rapids generating facility in Whitehorse.



mission

To enable Yukon's prosperity with sustainable, cost-effective and reliable electricity

values

- Safety
- Accountability
- Continuous Improvement
- Teamwork
- Professionalism
- Good Corporate Citizenship

vision

To establish a sustainable legacy for Yukon's future

message to yukoners

Our 10-Year Renewable Electricity Plan is based on our vision of supplying Yukoners with an average of 97% renewable energy by 2030. While it's a terrific plan for Yukon, a plan is only as good as its execution.

Over the last two years, Yukon Energy has made significant progress in advancing the projects needed to achieve this ambitious renewable energy target and to supply Yukoners with the sustainable, reliable and cost-effective electricity they need.

In January 2022, we signed an Electricity Purchase Agreement with Tlingit Homeland Energy Limited Partnership (THELP) to purchase renewable and dependable capacity and electricity from the Atlin hydro plant owned by the Taku River Tlingit First Nation. Working closely with THELP, we also successfully lobbied Ottawa to secure $150 million in grant funding towards the $240 million project, ensuring that the electricity we buy from Atlin is affordable for Yukoners.

As a result, Yukoners will receive 8.5 megawatts of dependable capacity and 34 gigawatt hours of clean, renewable hydroelectricity every winter, starting in late 2024. That's roughly the same amount of electricity used by 2,800 Yukon homes annually, and will eliminate the need for four rental diesel generators each winter.

The Grid-Scale Battery Project is another critical piece in our renewable energy plan. Once completed, the 7 megawatt/ 40 megawatt-hour battery will give us the means to store excess renewable energy generated during off-peak hours and store it for when we need it most – during times of peak demand or as emergency backup. We've done the research and planning, secured federal funding, entered into partnership agreements with Ta'an Kwäch'än Council and Kwanlin Dün First Nation, selected a site on Kwanlin Dün First Nation settlement land slated for future development, selected a battery vendor, procured the battery itself, and started the actual construction.

Construction will be largely done in 2022 with the battery scheduled to come online the following spring. Over the 20-year life of the project, the new battery is expected to reduce carbon emissions in Yukon by more than 20,000 tonnes.

We also successfully completed the Mayo to McQuesten Transmission Line Replacement Project in 2021, a $34 million investment in Yukon's energy and economic future. Working within Covid-19 protocols and restrictions, the project came in on budget and with no Covid-related incidents. This project will improve power quality and reliability, improve public safety and enable future growth around Mayo and Keno with renewable energy sources.

2021 Board of Directors

Lesley Cabott (Chair)
Clint McCuaig (Vice Chair)
Blair Hogan
John Jensen
Simon Lapointe
Mike Pemberton
Rod Savoie
Rob Schneider
Rod Snow
Jim Stephens
Christina Thomas

How we've executed our plans over the last couple of years is as important as the progress we've made on individual projects. Throughout our work, we've remained firmly committed to creating opportunities for First Nations governments and businesses to participate in the energy sector, and held ourselves accountable for our environmental, social and corporate impacts.

For us, as invested Yukoners, sustainability includes a commitment to reconciliation and honouring the spirit and intent of the Final and Self-Government Agreements – a commitment to walking with Yukon First Nations.

We've made progress, as evidenced in the projects above and through the implementation of our First Nations procurement policy, staff training in First Nations cultural awareness courses, a framework for partnership options and more support for First Nations initiatives.

Supplying Yukoners with sustainable, reliable and cost-effective electricity is a constant balancing act. While a lot of work remains to be done to achieve our 97% renewable electricity target, we've made excellent progress so far on critical projects and the partnerships needed to pave the path in coming years.

I would like to express my thanks to the Yukon Energy Board of Directors for their firm commitment to building Yukon's sustainable energy future; to all Yukoners, who through their participation in the many engagement events we host, continue to tell us to invest in renewables; and to our employees, who work hard each day to execute our plan with all our partners.

This is an exciting time to be a Yukoner and a member of the Yukon Energy team. I look forward to continuing to report on our progress in coming years.

Lesley Cabott
Chair
Yukon Energy Corporation
Board of Directors

president's welcome

Every year comes with its own issues and challenges. Looking back, it seems that 2021 had far more than its fair share. It was a year of both internal and external challenges that tested us and stretched our staff and resources to the max. While many factors were beyond our control, how we dealt with them was what we could control.

We dedicate the 2021 Yukon Energy Annual Report to the people that met the challenges: the employees of Yukon Energy Corporation.

We're honoured to tell the stories of what was accomplished through their eyes, work and voices – of what they took on when the floods came, when the temperature dropped, when Yukoners set another record for peak demand, when Covid-19 threatened to disrupt everything, and when we needed new partnership models to move ahead with projects.

If it were not for the people of this organization stepping up, taking responsibility, going farther, thinking harder, planning better and simply doing the work that needed to be done to meet the demands placed upon them, it all could have ended quite differently. Instead, 2021 will be remembered as the year in which:

- We dealt with flood waters through advance forecasting, planning, innovative and creative teamwork, and putting all hands on deck for the big effort when it counted most on a July holiday weekend.
- We managed through another record peak for electricity demand with leadership from staff at our System Control Centre and other operational departments, and help from our partners and biggest customers.
- We strategized a rate increase that would have nearly zero impact on Yukoners' electricity bills.

"Individual commitment to a group effort – that is what makes a team work, a company work, a society work, a civilization work."

– Vince Lombardi

- We developed new partnership models for working with First Nations governments and development corporations that would lead to best practices and generate benefits in: the Atlin Hydro Expansion Project with Tlingit Homeland Energy Limited Partnership; the Whitehorse Rapids Fish Ladder/Hatchery Working Group with the Government of Carcross/Tagish First Nation, Ta'an Kwäch'än Council and Kwanlin Dün First Nation; and the Grid-Scale Battery Project with Kwanlin Dün First Nation and Ta'an Kwäch'än Council.
- We broadened our thinking about safe workplaces in light of Covid-19, with a Mental Wellness Committee and a Work from Home program.
- We completed the $34 million Mayo to McQuesten Transmission Line Replacement Project on budget and Covid-free, in spite of having to work within a global pandemic.

It was a year in which our people committed to something bigger than themselves and then leaned on each other for strength, motivation and support.

I am proud to affirm and salute all Yukon Energy employees who, every day, work to enable Yukon's prosperity with sustainable, cost-effective and reliable electricity.

Andrew Hall
President and CEO
Yukon Energy Corporation

Photo credit: Ed Peake

2021 at a glance

generating capacity in the summer

132

megawatts

generating capacity in the winter [1]

105

megawatts

peak demand [2]

104.42

megawatts

renewable generation

92

per cent

electricity generated

534

gigawatt hours

0

lost time injuries

kilotonnes

23.1

cumulative greenhouse gas emissions (excluding fleet)

[1] caused by a lower supply of hydro resources during winter months
[2] recorded on December 16, 2021; previous record of 103.84 MW was set on January 14, 2020

A long night on the peak

On the night of December 15, 2021, most Yukoners were tucked safely in their beds, snuggled deep under the covers, while outside the temperature dropped.

And dropped…

Mike Hannah, Supervisor of Yukon Energy's System Control Centre, was not one of those Yukoners. He and others from Yukon Energy were busy that night making sure there were enough generation assets online to meet the energy peak expected the following morning.

"The stress and strain on our workers and system kept rising as we approached peak demand in the early morning," he recalls.

At 7:51 am on December 16, Yukon set a new record for peak electricity demand of 104.42 megawatts.

Peak demand simply means the largest amount of electricity Yukoners need at the exact same time. Meeting winter peaks is one of Yukon Energy's largest challenges. As an electricity system not connected to any other grid in North America, Yukon Energy only has itself – at times with the help of ATCO Electric Yukon and Yukoners – to supply all the electricity Yukoners need at any given time.

What exactly is at stake during a peak?

"Restoring a power outage at 40 below takes a lot more electricity than a power outage in the summer," says Mike. "You've got everybody's furnaces and heaters kicking in all at once – it's two or three times the regular load."

To guard against this very issue, Mike needs to ensure the system keeps up its spinning reserve – capacity that is online and ready to respond very quickly to sudden demands.

"We need spinning reserve to cushion the system, to restore power after an outage." Typically, that spinning reserve is in the hydro units that run below capacity during the winter. "That's easy in the summer," says Mike. "With plenty of water and low demand, it's easy to have reserve. It's much more difficult in winter when you're trying to generate as much power as you can with low flows to meet high demand."

There is a lot of work for Mike and Yukon Energy crews when it gets down to 30 or 40 below. The Corporation needs to deploy all its resources to monitor and make adjustments for demand.

But whatever problems and issues he deals with, one thing that never lets Mike down is the commitment of Yukon Energy staff.

"That's really what's keeping the power on in Yukon. They're doing an amazing job. I just wish Yukoners could see the lengths our people go to – the line crews, the repair crews working out in 30 to 40 below so everyone can wake up in a warm, well-lit house."

2019–2024 strategic priorities & performance

Strategic Priority	Performance
Generate reliable and renewable energy	In 2021, 92% of the electricity we generated was renewable because of high water levels and inflows in the Whitehorse, Mayo and Aishihik reservoirs. We were also able to continue delivering reliable electricity to Yukoners during the winter by using liquefied natural gas and diesel when hydro resources weren't available. Our 10-Year Renewable Electricity Plan outlines the ways we intend to generate an average of 97% renewable electricity by 2030. In 2021, we made great progress on this plan by: • Connecting the first independently owned solar farm to the Yukon grid and signing an agreement to purchase solar power from a third Independent Power Producer as well; • Advancing work on our Grid-Scale Battery Storage Project; • Completing upgrades to our Whitehorse #2 and #4 hydro units to allow us to generate more renewable electricity; and • Signing an Electricity Purchase Agreement to purchase hydro power from Tlingit Homeland Energy Limited Partnership's proposed Atlin Hydro Expansion Project.
Secure long-term sustainable financing	We worked with our shareholder, Yukon Development Corporation, to secure near-term funding for projects outlined in our five-year capital project plan.

Strategic Priority	Performance
Develop mutually beneficial First Nations partnerships	In 2021, we focused our efforts to strengthen relationships with First Nations governments where we have current operations. We hired Chris Milner, Vice President of Government Relations, whose work includes developing a framework for First Nations partnerships, advancing our work on reconciliation, and creating procurement and contracting opportunities for First Nations-owned businesses. In January 2022, we signed a lease agreement with Da Dan Developments, a subsidiary of Chu Níikwän Development Corporation, for a 25-year lease on the land needed for the battery. Businesses owned by Kwanlin Dün First Nation and Ta'an Kwäch'än Council have, and will continue to have, a significant role in the development of the battery, including investment, procurement and contracting opportunities, as part of the overall project. In 2021, we also continued to work with representatives from Champagne and Aishihik First Nations on the long-term relicensing of the Aishihik hydro facility.
Achieve excellence in employee engagement	We continued to develop strategies and take action to effectively recruit, engage and retain employees. We developed a Work from Home program to provide an alternative method of meeting the needs of employees and the company. The approach focuses on health and safety, records and security, and work–life balance. An employee-led Mental Wellness Committee was also established to encourage and elevate conversations about mental wellness in our workplace.
Streamline and clarify governance	In 2021, a Protocol Agreement was signed between the Chair of Yukon Energy Corporation's Board of Directors and the Chair of Yukon Development Corporation's Board of Directors. The Agreement describes Yukon Energy's accountabilities in relation to Yukon Development Corporation's performance expectations for the utility. It outlines both corporations' agreement to each of their respective roles and responsibilities, and provides a framework that encourages strong corporate governance of Yukon Energy.
Provide outstanding, reliable customer value	We were successful in our efforts to provide Yukoners with bill stability, while making the investments needed in Yukon's electricity system to meet growing demands for electricity and to replace aging assets. With the Yukon Utilities Board's support, our two interim rate increases in 2021 were applied on the same days that other charges on electricity bills were either reduced to zero or came off bills. The net result was nearly zero change to what average residential and commercial customers paid for electricity each month.

Need a rate increase? Call the chauffeur

As Director of Finance, **Jason Epp** generally tries to "…stay out of the way and make sure everything works."

And there's plenty to make sure about, considering he's responsible for overseeing accounting, payroll, budgeting, forecasting, banking, the corporate year-end financials and financial filings with the Yukon Utilities Board (YUB).

And when he's not at the office? "I'm mainly the chauffeur for my three kids, ages 11 to 13. Every day, all I do is figure out where and when to drive them to their numerous and various activities."

While he's only a numbers guy at the office and a humble chauffeur at home, Jason has managed to understand when his fellow Yukoners are hurting and need a break.

"One thing they don't need is to be hit by a rate increase when they're already dealing with the impacts of Covid and the cost of everything else going up."

"Because we are owned by the Yukon government – which is owned by Yukoners themselves – we have a fiduciary responsibility to get this right. We live here too, and we need to be as fair as possible to all Yukoners. Our rate increases are meant to give us a stable, reliable electrical system, without the need to make excess profits. Any of the 8.2% profit that the YUB allows us to make simply gets re-invested back into infrastructure."

Like all businesses, Yukon Energy must deal with rising costs, aging infrastructure, maintenance and replacements. None of those were going away and they were beginning to add up.

The last time Yukon Energy completed a rate filing was for 2018. A General Rate Application (GRA) was not submitted to the YUB for a rate increase in 2019. Then, in 2020, the Covid-19 pandemic hit.

Not wanting to deliver another blow to Yukon ratepayers, Yukon Energy decided the right thing to do was to defer the GRA for another year.

But even a year later, the company struggled with the idea of increasing the burden on Yukoners.

"We came up with a strategy for lowering the impact on ratepayers: to coordinate any increase with decreasing riders." The Corporation applied for the rate increase it needed but tied its implementation to a schedule of riders that were due to come off the bill.

"Normally, as soon as we file the GRA, we ask for approval of interim rates. That would have increased bills by about 6% in January, 2021. But we didn't ask for that. Instead, we asked for a part of the proposed increase to become effective July 1, 2021, the same day fuel rider F was reduced to zero. Since it was for an equivalent amount, there was no change to the average ratepayer's electricity bill."

The second part of the interim increase was delayed until December 1, 2021, when the Yukon Energy 2017–18 true-up rider came off the bill.

"By the end of the year, the net impact for the average ratepayer was nearly zero. And it stays this way until our next GRA."

Jason sees the benefits of the net-zero strategy extending several years into the future.

"The last impact on Yukoners' electricity bills was the beginning of 2020. The 2021 increase was 'net 0' so it made no real impact. The soonest we can submit another GRA would be in 2023 or 2024," he said.

"In this climate of rapidly escalating prices, I think three to four years of stability in energy pricing leaves Yukoners well served."

Call the doctor

If the runner (the part that spins when driven by the force of water) is the heart of the turbine, then **Geoff Dunbrack**, Manager of Mechanical Engineering, is Yukon Energy's heart surgeon.

"Replacing the runner on Whitehorse unit #2 (WH2) was a large project," says Geoff. "It was originally installed in 1957 and it was nearing the end of life. Plus, the technology has progressed beyond what was available 60 years ago."

What does the runner do? "It turns hydraulic energy into mechanical energy. It's basically the big propeller that you see in hydro plant illustrations," says Geoff.

Replacing the runner would make WH2 more efficient, by producing more power from the water running through it. In addition, the generator itself could be rewound for more power, and the controls and systems modernized.

The process started with two years of engineering design and planning. "Then once we got up and running, the runner had to be cast in Europe, transported to Canada where it was machined, and then shipped up to Yukon," says Geoff.

WH2 was out of service for about nine months for that work, plus an additional month and a half for commissioning.

"But you walk around it now and a lot of it looks brand new and modern. We'll be reaping the benefit from this work for the next 40 years." That benefit, aside from replacing end-of-life equipment, amounts to deriving more energy out of the same amount of water flowing through the turbine.

The project was completed and in service by October, 2021.

Work on Whitehorse unit #4 was of a different nature.

"It's our biggest unit, producing 20 megawatts of electricity. But it's had issues since 1984 when it was installed. There was a bottleneck that limited output simply because of a limitation on the wicket gates. It was not able to net 100% generation."

By replacing the servo motors that control the wicket gates, the bottleneck was removed and 100% potential restored. The benefit is that Yukon Energy can now get even more energy from its biggest unit.

The work required a month of shutdown in May, 2021, after winter peak demands, but before the seasonal freshet.

Geoff gets a lot of personal satisfaction from seeing these types of large projects through to completion.

"It's good for clean electricity and good for Yukon. And if it's good for Yukon that means it's meaningful to me."

What meaningful work is on the good doctor's horizon? "We're just now having a look at WH1. It's the next possible thing we're going to uprate."

Photo credit: Jim Petelski

2021 corporate goals & performance

Goal	Performance
Zero high-risk injuries	There were no high-risk injuries in 2021; however, we did have two serious incidents where the potential for employee injury or fatality existed. One incident involved an employee in a single-vehicle rollover; the other involved two employees who inspected a shore bank less than 24 hours before the shoreline collapsed. For us, there is nothing more important than each and every one of our employees making it home safely each day. While no one was injured in these incidents, the fact that it could have happened, and with serious consequences, hits too close to home. In 2022, we will modify our corporate safety goal to be *Zero Serious Incidents with Fatality Potential* to ensure that we continue to improve the systems, procedures and practices we have in place to make sure everyone goes home safely.
Achieve a return on equity of 8.7%	Our 2021 return on equity is forecast to be approximately 9.0%, subject to final direction from the Yukon Utilities Board on our 2021 General Rate Application.
Manage 10 or less controllable outages	We had nine controllable outages in 2021.
Execute a Covid-19 recovery plan	A year of Covid-19 and the increased stress it placed on employees added another layer to safety considerations. A Mental Wellness Committee was established to promote mental wellness at Yukon Energy. It consists of three representatives each from the union and management, and meets quarterly. All members were enrolled in an online Psychological Health and Safety in the Workplace training program with the University of Fredericton. The committee sponsors initiatives and activities to counter workplace harassment and bullying and remove the stigma from mental health injuries. When Covid-19 made gatherings in open offices difficult, many employees began working from home as a way of managing their risk and exposure. At-home workers receive advice, equipment, and home inspections for occupational health and safety standards before they make the move.

Goal	Performance
Sign an Electricity Purchase Agreement for the Atlin Hydro Expansion Project	In January 2022, Yukon Energy signed an Electricity Purchase Agreement with Tlingit Homeland Energy Limited Partnership (THELP) that will increase the supply of dependable renewable electricity in Yukon each winter starting in 2024. The Electricity Purchase Agreement confirms THELP's plans to build, own and operate the Atlin Hydro Expansion Project, a project designed to expand the infrastructure and power production capacity on Pine Creek from 2.1 megawatts to approximately 11 megawatts. The Electricity Purchase Agreement also outlines our intention to buy renewable energy and capacity from the Atlin Hydro Expansion Project for 40 years at prices less than or equal to the cost we would otherwise pay for electricity generated using liquefied natural gas and diesel. When complete, the Atlin Hydro Expansion Project will add 8.5 megawatts of dependable capacity to the Yukon grid, eliminating the need for four rental diesels each winter. It will also generate about 34 gigawatt hours of electricity each winter – roughly the same amount of electricity used by about 2,800 Yukon homes annually. The Electricity Purchase Agreement signed by Yukon Energy and THELP is subject to a number of milestones being met in 2022, including: a review by the Yukon Utilities Board (YUB); ongoing consultation with First Nations in the project area; approvals from Taku River Tlingit First Nation government and Yukon government; and all government grant funding and project permits being obtained by THELP.
Complete the Mayo to McQuesten Transmission Line Replacement Project on budget	The Mayo to McQuesten Transmission Line Replacement Project was completed on budget and Covid-free in 2021. The project took place on the Traditional Territories of the First Nation of Na-Cho Nyäk Dun and Selkirk First Nation. As a result of this work, power quality and reliability will improve in the Mayo and Keno areas. It will enhance public safety and support future growth and development in the region with more renewable electricity. The project consisted of two major stages: building a new 31-kilometre, 138-kilovolt transmission line to replace a 65-year-old transmission line that had reached end-of-life, and adding equipment at the Stewart Crossing South substation to improve power quality in central Yukon. With total project costs coming in just shy of $34 million, the project was delivered on budget and without any cases of Covid-19. Yukon Energy's investment in the project was roughly $7.8 million. Industrial customers that use the new transmission line will pay 85% of the fixed annual costs of the line. Funding for the project was also received from the Government of Canada's Green Infrastructure Stream (GIS) of the Investing in Canada Infrastructure Program ($22.7 million), and Yukon Development Corporation who provided $3.5 million towards planning costs (formerly the Stewart to Keno City Rehabilitation Project).

A whole lot of job satisfaction

As the Coordinator of Electrical Projects, there were three things that particularly fascinated **Al Porter** about the Mayo to McQuesten Transmission Line Replacement Project:

1. The amazing Swiss watch technology that is the Static Var Compensator;
2. The variety of international experts he worked with on the project; and
3. Who was eating the turkey sandwiches in the lunchroom?

Al works as the interface between Yukon Energy and its contractors. On the $34 million Mayo to McQuesten project, he worked mainly on the Stewart Crossing substation upgrade rather than the line replacement part of the job.

The latter featured replacement of the old, faltering 69-kilovolt transmission line, with a new, larger-capacity 138-kilovolt line.

The project took place on the Traditional Territories of the First Nation of Na-Cho Nyäk Dun and Selkirk First Nation. It was needed to improve power quality and increase reliability in the Mayo and Keno areas, improve public safety, and support future growth and development in the region with more renewable electricity.

On September 5, 2019, the Government of Canada announced a contribution of over $22.7 million towards the project through the Green Infrastructure Stream (GIS) of the Investing in Canada Infrastructure Program. Yukon Development Corporation also provided $3.5 million towards planning costs.

"But I'm not a line guy. I'm a substation guy," says Al. "And installing the PCS 6000 Static VAR Compensator gave me a whole lot of job satisfaction – right from scraping the ground, through concrete, steel framing and installation."

The Stat-Com, a voltage conditioner, was the first of its kind in Yukon. "It stabilizes voltage so we don't see big power draws or drops as things come on- or off-line," he says. "We typically use capacitors and reactors for that, but this thing does it all – automatically! You just give it a voltage setting and it makes all the adjustments on its own."

The work took on a real international flavour for Al, as he tapped into contractor and engineer expertise from Switzerland, Germany, India and the Philippines. In keeping with the Swiss watch technology, most of the engineering expertise came from Switzerland.

Dealing with such an international group of contractors posed its own challenges during the Covid-19 pandemic.

"We worked out a set of protocols with the Village of Mayo and First Nation of Na-Cho Nyäk Dun to limit exposure, so that only certain Yukon Energy employees could go into town. That made me the go-to shopper for crew and contractors. The upside of that was we recorded no cases of Covid during construction."

"It's fantastic to have the reliable, cutting-edge technology that the new Stat-Com gives us," says Al. "In the old days, I'd be in town and people would point at me and say, 'You owe me a new TV!' While that was never really true, what is certainly true today is genuine system stability."

And what about the turkey sandwich?

"We first noticed a bag of apples torn apart in the lunchroom. Thought maybe it was mice. Next day, someone's turkey sandwich is missing. Then one day at the lunch table, I sensed something behind me. I turned to see a pine marten eating a sandwich!"

With the mystery solved, dirty looks around the table disappeared, and the substation crew moved forward once again as a cohesive unit.

Photo credit: Al Porter

Different interests, same journey

This is a story of two CEOs and how the thing they each wanted for their corporations turned out to be the same thing.

Andrew Hall is the CEO of Yukon Energy Corporation. His job is "…everything and nothing, so long as it ensures the company advances in its strategic direction." His is a company with a singular operational focus: generating and transmitting sustainable, reliable and affordable electricity in Yukon.

Peter Kirby is the CEO of the Taku Group of Companies. His job is "…everything from sweeping the floor to making the strategic decisions." His is a company made of many other companies with operations ranging from fish to construction to real estate – and – electricity generation and distribution.

And that's where their interests overlap.

"Our 10-Year Renewable Electricity Plan from 2020 is all about how we're going to meet Yukon's future electricity needs," said Andrew, "especially in light of Yukon government's climate change objectives and the electrification of transportation, home heating, and economic and population growth."

The plan identified a number of key projects to make that work. Purchasing electricity from an expansion of the hydro plant in Atlin was the first major one.

"And that could only become available if the independently owned Taku River Tlingit First Nation Development Corporation expanded its Pine Creek hydro plant, built a transmission line from Atlin to Jakes Corner, and agreed to sell the electricity to us on contract," said Andrew.

For Peter, the story of overlapping interests goes back to 2004, when the Taku Group won a BC Hydro Request for Proposals to replace Atlin's diesel generators with hydro energy. "We built our hydro plant and went online in 2009. The plant has performed extremely well since then, so the diesels have hardly had to run. That hydro plant was the linchpin for our growth and what we can do today," he says. "It gave us the money we needed to build capacity in people and equipment. It gave us credibility for taking on larger projects. But mostly, it developed and showcased our can-do attitude for getting things done."

The opportunity for the Yukon market is like the original project, he says, only smarter, making better use of the available water. It will require raising water levels in Surprise Lake by about 35 cm, and putting in place an extensive, year-round water monitoring program. When done, it will deliver 8.5 megawatts of dependable capacity to Yukon every winter.

"One of the things that made the collaboration so attractive to us was how far along the Taku Group was with the project," says Andrew. "They've got 10 years' experience running their plant, they've increased their storage range, and all the design work had already been done in preparation for expanding into the Yukon marketplace."

The Atlin Hydro Expansion Project will be built and owned by Tlingit Homeland Energy Limited Partnership (THELP), a company 100% owned by Taku River Tlingit First Nation (TRTFN) citizens. The project also includes construction of a transmission line between Atlin and Jakes Corner in Yukon.

The Taku Group and Yukon Energy worked together for two years to secure the grant funding needed to make the opportunity work. Without significant funding, Yukon ratepayers couldn't afford the Atlin power, says Andrew.

"Through a lot of collaboration, we lobbied Ottawa to secure $150 million in grant funding towards the $240 million project. Those are big numbers, but they're not uncommon for the North." The federal government is keen to support northern investment, he says, to play a part in reconciliation efforts and support First Nations business developments.

"This hydro opportunity sits right on the First Nations sweet spot," says Peter. "It does good things for the environment, reduces greenhouse gases, and generates revenue for First Nations communities."

It remains to be seen how the revenues will be invested by the community, he says. "But one of the biggest things for me as a TRTFN citizen is to see families who've struggled with residential school issues, poverty – to see them with jobs that provide their families with a good living and able to make improvements in their circumstances. That's what really matters to me. That's why we're doing this."

For Yukon Energy, the project ticked a lot of right boxes, says Andrew. "This is winter energy. They'll be storing water, filling the Surprise Lake reservoir in the summer and drawing it down in winter to deliver 8.5 megawatts of dependable capacity to Yukon. This will be equal to the output of four rental diesel generators, providing 10% of our total needs with clean, renewable, hydro energy. It helps us when we need electricity most, while helping us meet our climate change goals."

He sees this as a good model for collaborative relationships with First Nations. It works, he says, because they've taken care to align everyone's interests: the interests of a Yukon utility, a First Nation, the federal and Yukon governments, and Yukoners themselves.

Peter is especially proud of the collaborative effort between all the parties. "We share a respect for the uniqueness of the place where we live."

Where does the project go from here?

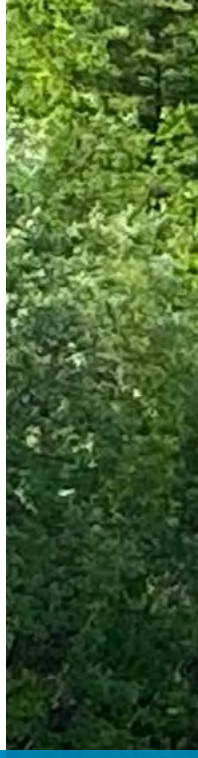
"For the next couple of years its hair-straight-back time," says Peter. "This whole process started in 2013, and there's been a little more energy put into it every year. Now we're flat out. Within a couple of years, we'll have a fully operational commercial plant."

For Yukon Energy, an Electricity Purchase Agreement that confirms all plans as well as the intention to purchase hydro power was signed in January, 2022. It is being reviewed by the Yukon Utilities Board. With approvals from both Yukon and Taku River Tlingit First Nation governments, it should be a done deal by fall, 2022, with a construction start in spring, 2023.

"This is our new reality," says Andrew. "First Nations want to be owners and investors in the energy sector. From our perspective, First Nation ownership of new generation assets is a great strategy."

"This is what we do," says Peter. "This opportunity helps guide us to respect the land and resources that nature has given us and respect each other in the process."

health, safety & environment



Safely home

Melanie Pettefer is the Manager of Health and Safety. Her department has one overriding responsibility: "To help ensure the workers go home in the same shape they arrived in."

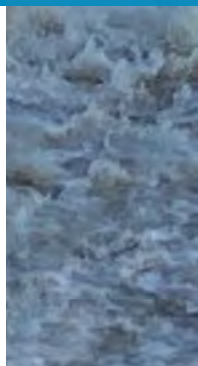
To do that, she and Yukon Energy's Safety Coordinator have implemented safety programs and procedures.

"It's easy to get complacent when you have long periods without even a band-aid," she says. What worries her is that while the injury incidence rate is low in the electric utility industry, the severity of injuries can be very high. To guard against that, safe work plans, job safety analysis and safety controls all need to be in place, all the time.

A year of Covid-19 and the increased stress it placed on employees added another layer to safety considerations. A Mental Wellness Committee was established with a goal of promoting mental wellness at Yukon Energy. The committee is made up of three representatives each from the union and management. It meets quarterly, engages in activities throughout the year, and reports to senior management and the Board's Human Resources Committee.

To help inform best practices, all members are enrolled in an online Psychological Health and Safety in the Workplace training program with the University of Fredericton.

"The employer has been really supportive," says Melanie. "Even though workplace psychological health and safety is a fairly new concept, they understand where some of the risks are for folks. In 2020, one third of all workplace injuries in Canada were related to mental health. So keeping people safe is more than just the physically safe way to do your job – it includes civility, respect, and not provoking the people you work with."



The committee has sponsored several initiatives and activities to counter workplace harassment and bullying. Its mental health first-aid strategy aims to remove the stigma from – and increase awareness of – the signs and symptoms of mental health injuries.

When Covid-19 made gatherings in open offices difficult, most Yukon Energy employees were directed to work from home to manage their risk and exposure.

"But you can't have people working at home, perched on their laundry baskets at the kitchen table," says Melanie. "We applied the same consistent ergonomic standards in their homes as in their offices." At-home workers receive advice, equipment, and home inspections for occupational health and safety standards before they make the move.

"The biggest risk, really, is people overworking, and losing touch with their colleagues." To help maintain relationships and collegial bonds, Yukon Energy is planning company-wide social gatherings such as a Christmas-in-July BBQ.

When looking to the future, Melanie envisions "hybrid" work programs.

"People may work from home the majority of the time but come into the office on a regular basis, possibly at hot desks, to stay in touch, work jointly on projects and generally maintain a workplace state of well-being."

Happily home

Wes Marsh is a Senior Payroll Analyst. He deals with payroll and benefits, labour budgeting and reporting.

When he's not working, he's a parent to a school-aged daughter and puts as much time as he can into cross-country skiing, hockey, running, biking and camping.

Wes is a busy guy and what he needs most of all is work–life balance. With Covid-19, safety protocols and social distancing made life very challenging.

"When the pandemic hit, everyone was sent home. It didn't work well for the operations staff. But for us finance staff, it turned out to be a really good fit. With the right technology, there was no physical reason to be at the office."

Wes turned a bedroom into his office and had it inspected so it met ergonomic and safety standards. "They gave us laptops and all the necessary apps, firewalls, an extra monitor, all the same stuff as in the office – and, in fact, I still have the office!"

Wes got all the flexibility he needed to manage his busy life, while still being able to get into the corporate office occasionally to confer with colleagues, stay in touch, and access some of the resources there.

"I'm one of those for whom the pandemic slowed me down to the pace that works for me and suits my lifestyle," he says.

Some of the key benefits for him have been the time and gas savings of the commute, caring for his daughter before and after school, exercising when he needs to, and being able to do his work at the times in the day that suit him.

"I find it far more efficient, really, especially for meeting deadlines," he says. "I can shut everything else down – no idle chit-chat or other distractions – and focus on the job at hand."

Does Wes see himself returning to the way things were some day?

"I'm looking forward to doing this on a permanent basis," he says. "In fact, I've noticed my former cubicle space is slowly filling up with storage boxes – maybe that's a good sign?"

To have and to hold

For **Kevin Maxwell**, Resource Planning Engineer, forecasts are essential tools for Yukon Energy to make critical decisions about how to direct their actions for the year ahead. It's all about water: having enough to generate renewable energy, but not so much that it damages infrastructure and impacts lives.

"The number one goal of our operations is to minimize thermal and maximize hydro," he says. "The more we can do that, the lower the cost to the environment and to Yukon ratepayers. Every drop of water spilled is a potential loss to us. So my number one priority is: don't spill water."

To know how much water to have and to hold every spring and summer makes long-term load forecasts a critical tool.

Annual forecasts start with Yukon government snow surveys, which consist of samples from different locations. Those surveys are compared to those from previous years and to historic snowpack data.

"Lots of snow doesn't necessarily mean we're going to have flooding; there are other factors involved," says Kevin. "We feed snow reports into long-term snowpack forecasts and long-term weather forecasts. From that, we get a forecast about inflow into our basins," he says. "A long-term weather forecast for a drier, colder summer, for instance, really mitigates the snow melt."

In the Whitehorse region, typically one third of the inflow comes from snow, roughly another third from rain, and the final third from glacier melt. "That last one is the critical one because glacier melt is totally weather-dependent. While people can become quite concerned about the snowpack, it's only part of the picture."

One critical step is to decide which long-term weather forecast is most likely to occur. From there, the company begins to determine how things might go. A big consideration is the timing of freshet. Freshet refers to the spring thaw that puts meltwater into rivers and lakes. It can last weeks and put significant quantities of water into watersheds.

"The timing of freshet, whether it's early or late, makes a huge difference. A late freshet can be as much as six weeks beyond the normal window. The problem is you can't pass flood waters until the lake hits its high point. A late freshet causes more flooding."

The impacts of climate change are more difficult to take into account when forecasting. For one thing, says Kevin, the actual weather at the time has such a large and immediate impact that it is hard to see others.

"What we are seeing in our modeling is more extreme events. The range of uncertainty is now wider due to climate change."

Climate change affects both high and low forecasts. "A couple of years ago, we had three peak demand days in a single year, when normally there's only one in a year. So even while, on average, temperatures are getting warmer, they are also becoming more extreme."

During the 2021 flood season, four things worked in the company's favour to keep a dire situation from becoming much worse.

1. Yukon Energy opened up gates at the Lewes River Control Structure about two months earlier than normal.
2. There was an early freshet, which minimized flooding.
3. It was a colder and drier-than-usual summer, which slows down glacier melt.
4. Yukon Energy reduced Schwatka Lake levels, which gave Marsh Lake time to lower.

"A lot of people think that lowering Schwatka is the same thing as lowering Marsh Lake. It doesn't work like that," says Kevin.

Schwatka and Marsh Lake are tied together by the bottleneck of Miles Canyon. The canyon acts much like a water hose, restricting the flow to what can physically pass through that hose. By lowering Schwatka Lake levels, the pressure across Miles Canyon increases. This is the same thing as increasing the hose pressure, and with a higher hose pressure, more water can be passed.

One other measure the company took to increase water flow was removing the boat lock at the Lewes River Control Structure. "That was equivalent to the flow going through one and a half gates. This was a good idea, very helpful, but it came at a pretty steep cost." In spite of all the shoring and sandbagging, the river eroded the footings and took out the centre pillar. Now the lock is inoperable and closed, and Yukon Energy is facing what is likely to be a multi-million-dollar repair bill.

The issue of balancing upstream and downstream flows comes up regularly. "That's what people ask: couldn't we put more water downstream?"

In the summer when Marsh Lake gates are all 100% open, Whitehorse is a run-of-the-river facility. This means the flows are naturally regulated by Miles Canyon and the flows only increase when Marsh Lake increases (i.e., an increase in pressure as in the hose analogy above).

"The only control we have in the summer is to raise or lower Schwatka Lake," says Kevin.

In winter, Yukon Energy must deal with flooding in Marwell due to icing. "Yukon Energy's first priority is to protect the environment and property. So, because Marwell is susceptible to ice jams and backups, we reduce our release rate from 250 cms to 180 cms. Sometimes, when icing gets really bad, we'll back off even more, to 160 to 170 cms. This results in upwards of 14 megawatts of Whitehorse capacity not being used."

"So," says Kevin, "between Miles Canyon and Marwell, we literally are stuck between a rock and a hard place."

There are potential solutions – expensive ones. Dredging the river or increasing the dike could alleviate the icing problems in Marwell.

But what Kevin would really like to see some day is a pumped storage facility. "What a great benefit that would be. We could capture all that spilled water, store it, and re-run when we need it. Water is money!"

It all comes back to his number one priority: don't spill water. "Give me a wet, rainy season and, as long as it doesn't cause property damage, it's just free money pouring into ratepayers' coffers."

"While we cannot predict the future, we will most surely live it. Every action and decision we take – or don't – ripples into the future. For the first time, we have the capability, the technology, and the knowledge to direct those ripples."

– Jacque Fresco

When the weather got nice, we got worried

Lowell Tait is normally a Maintenance Mechanic at Yukon Energy, working on "…anything with nuts and bolts and moving parts."

But last summer was not normal times, and he shifted into a new role as the Hydro Supervisor for the flood period.

"I'm a born and raised Yukoner and I've seen that river about every day of my life, its graceful, silent movement through the city," says Lowell. "That summer I watched as it increased day by day, during the biggest water year we've ever had. That's when I realized the awesome power it had."

Concerned by the high snowpack, Yukon Energy prepared for flooding well in advance, gathering resources and making plans to control the water.

"We'd worked out three scenarios based on predictions and modelling: best case, likely case and worst case. Then we started preparing for the worst case."

The crew went to work shoring up facilities on two fronts, the Lewes River Control Structure just down from Marsh Lake, and the hydro plant at the Whitehorse Rapids dam.

At the control structure, shorelines at risk of erosion were braced with sandbags and mega bags. "The control gates were pinned up to their maximum levels," says Lowell. "When the water threatened to reach even that, we pulled the gates out altogether."

When the water kept rising, the decision was made to remove the boat lock gates for a bit more unrestricted water flow. "Now that's a pretty big step and an unusual move for us," says Lowell. "We had to bring in work crews, operators, contractors, excavators, trucks and helicopters to help."

There was debris clearing from the structure, daily water level monitoring and communications, and public-access restrictions and safety controls near the control structure.

"It's weird, but when the weather got nicer, we got more worried. The biggest jumps in river rise came after warm and sunny days. That's when the mountain snow and glacier melt came down."

And that's what happened when the river began to rapidly rise to concerning levels – over the July long weekend.

"That holiday weekend, it was all hands on deck. Lots of employee sacrifices were made, lots of contractors made the work a priority – and that work was bracing up the structure to try and keep it in place."

Meanwhile, at the hydro plant, any water coming downriver was either going through the spillway or through a hydro unit. It became a constant balancing act, controlling upstream and downstream flows.

"We had to do some sandbagging along low shorelines. We installed tiger dams in the hydro facility itself, next to the generators. Tiger dams are large water bladders that anchor down and seal out water better than sandbags because there are no seams. So there we were, introducing water into the facility!" says Lowell.

"But they would hold back any incoming water, creating a barrier zone that we could control with pumps. Bottom line, you cannot have water hitting the hydro units – you need to keep those things going!"

One huge issue was dealing with debris. "Shorelines that had been collecting debris for years and years – as well as things like floating docks – all that got flushed downriver by rising water. It collected at the control structure and in the trash racks above the spillway at the intake. It was a constant job and challenge to keep it clear, with lots of staff hours, dump trucks and logging loaders involved."

All the work at the hydro plant was preventative. The measures worked and kept water out. In the end only a few points along the shoreline were reached by water.

"There was just a lot of teamwork throughout this period, from planning and execution, having the right gear on standby, monitoring both automatically and manually, constant communications with the whole group, and making sure all the equipment stayed in working order."

For Lowell, it was an intense period of putting heads together, learning and getting creative. "It was ultimately rewarding how we dealt with it as a group. A big collective group effort, good teamwork, evening and weekend sacrifices – we learned a lot as a corporation." While they prepared for the worst case, they ended up with the likely case, says Lowell.

"I think where we really shone was in the full team effort and commitment of employees and contractors. Their sense of responsibility to their community had them dropping whatever they had going to help us turn away the flood waters of 2021."

Photo credit: Ed Peake

customers, community & partnerships

Customers

We are committed to providing sustainable, reliable and cost-effective electricity to our customers. We also believe in providing Yukoners with the information and tools to better manage their electricity use and to conserve energy, when and where possible.

Reliability

More Yukoners are turning to electricity, instead of diesel or propane, to heat their homes and businesses. With that shift, our ability to supply Yukoners with electricity they can trust to be there when and where they need it is becomingly increasingly important. Our ability to supply electricity is not only about keeping the lights on. It's also about keeping Yukoners warm and safe during Yukon's cold and dark winters, when demand for electricity is the highest.

This means we're always planning for cold weather, emergencies, and increased demands for electricity. That's why we rent diesel generators each winter as our insurance policy against prolonged outages, until we can build or purchase more dependable sources of renewable energy and capacity.

In 2021, we rented 17 portable diesel generators – the same number as last winter. As new records for peak electricity demand continue to be set year after year, two things are clear: Yukoners are using more electricity than ever before, and more sources of dependable electricity are needed at the flip of a switch during the winter.

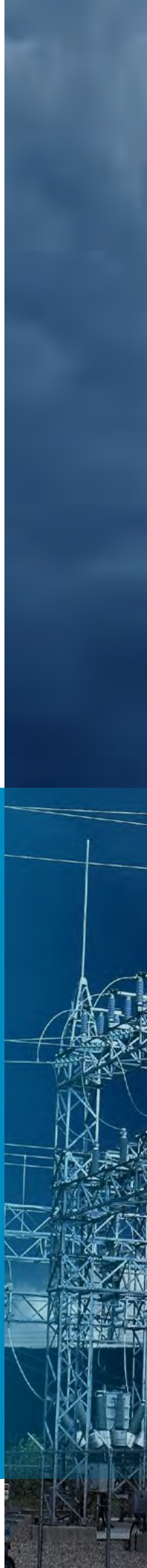
As in the previous year, ten of the rental diesel generators were installed in our Whitehorse parking lot in 2021, and the other seven at our diesel power plant in Faro.

Outages

Number of outages in 2021: 56

Top causes of system outages:

1. External interference (e.g., third-party contact, wildlife)
2. Equipment failure
3. Tree contact



A program so smart, even the supplier can't stop it

When the Peak Smart Pilot Program launched in 2019, Yukon Energy worried if enough Yukoners would be interested in signing up for the program.

Turns out there was nothing to be concerned about, says **Mila Milojevic**, Vice President of Resource Planning and Regulatory Affairs.

"Peak Smart was a pilot project to see if we could reduce the energy used by customers during peak times without interfering with their home needs," says Mila. If it could be done, then rather than having to generate more electricity to cover increased demand, Yukon Energy could shift customers' use of electricity to a lower peak period.

"It works by us installing devices on customers' hot water tanks and special thermostats for their baseboard heaters, both of which Yukon Energy can then control."

Funding for the project was provided by Natural Resources Canada, Yukon Development Corporation, ATCO Electric Yukon and Yukon Energy.

The program was entirely voluntary, and the company made clear to participants that they could take back control of their devices whenever they wanted or needed to. Response was excellent and the pilot became fully subscribed with over 400 homeowners signing up. "I'm just so grateful to all the Yukoners who were prepared to go down this path with us. It is really encouraging to see their willingness to participate in innovation in the territory."

Ultimately, Yukon Energy was looking for solutions. "There's ever-increasing demand on the grid. It's already approaching maximum loads, forcing us to rent more diesel generators," says Mila. Looking to the future, she sees new policies and electrification initiatives putting ever-greater demands on the system.

Addressing demand response rather than simply meeting demand offers an elegant solution – or at least part of the solution. "What Peak Smart can do is help us balance out the peaks and manage the demands," says Mila.

So how did it all play out?

"Well, there was a bit of a hitch," says Mila. "We got through one winter and then the device supplier shut down unexpectedly. We couldn't get any more devices to install on customers' heaters, and no more support for those already installed. We only got one season out of the pilot rather than the two we planned for."

However, at the end of the pilot, devices in over 250 homes were installed, and they gave a good account of how peak shifting could work, says Mila. "Results definitely show that we can reduce peak demand, especially when it comes to baseboard heaters."

Peak usage shifts were particularly significant when it came to the time when houses were pre-heated in the morning. Pre-heating typically took place a couple hours before the peak – at times when demand for electricity is low, with no corresponding discomfort to homeowners during the morning or evening peak.

"It's really quite exciting," says Mila. "This works – this works in Yukon!"

Results were so encouraging that Yukon Energy is now planning for a full-scale program rollout by 2024 as part of the new suite of demand side management programs the company is working on.

"The silver lining of our experience with the supplier suddenly shutting down is that, in the future, we will be better prepared for supplier risk. In other words, being more careful about who we vet and who we ultimately select, taking into consideration program stability and continuity."

Before that stage, the company must install a comprehensive demand response management system. That's the software used to manage peak shifting. "That software installation is a pretty big deal," says Mila. "There's plenty of feasibility and due diligence we have to do first. We hope to have that installed and operational in 2023."

"The big takeaway is that we've proven that it works. It gives us a tangible program that we can put into place in the near future and make a meaningful impact to reduce peak demand in Yukon.

It really is the outcome you want for a pilot program: success and a path forward."

Photo credit: Archbould.com

Community

Back to the land

Winning a prize is one way of drawing attention to your organization.

Winning the Arctic Inspiration Prize gets you that attention – plus $100,000 to work with.

That's what happened in 2017 to Rivers to Ridges, a Whitehorse organization led by **Wren Nicolardi** and **Emily Payne** that designs, delivers and supports outdoor and land-based programs for young people.

"The award money went to designing and launching our forest school," said Wren Nicolardi, co-founder of the company. "It's a land-based education initiative that we were developing with a focus on preschool programming."

What the prize also did was catch the attention of Yukon Energy.

"Through the publicity around the award, Yukon Energy got a sense of what we do. They reached out for more information about us."

What they found was an organization committed to programs that guide young people towards a meaningful connection with the land through empathy, awareness and community. Community means many things including the importance of building or deepening relationships with the original people of the land. They found an organization working towards an active, educational approach to reconciliation.

Yukon Energy got on board with a three-year sponsorship starting in 2020, contributing $9,000 a year into Rivers to Ridges program development. The money enables Rivers to Ridges to welcome First Nations Elders and Traditional Knowledge Holders to spend time with children during the program, while removing any barriers to access by providing food, materials, travel coverage and youth support.

"Yukon Energy has long had an interest in First Nations education opportunities." says Wren. "They've been great supporters – and very flexible, especially when so much shifted and had to be changed with Covid."

Wren and Emily consider themselves settlers on the land, and this brings with it certain responsibilities. Many of the kids in Rivers to Ridges' Whitehorse programs are settlers too. The organization works with First Nations Elders and Traditional Knowledge Holders so that voices from the people of this land are present during programs. "Sometimes, Elders just want to be present. They know they are always welcome;" Wren says, "that there's always a chair for them, a cup of tea or lunch." This fosters closer interactions with Elders, and means that "kids get to leave with a better sense of what's possible when we learn from knowledge systems and ways of being that are based on the lands we're on," they say.

While these programs have been embraced by a broad and diverse cross-section of the Whitehorse population, First Nations kids were not always well represented. Partnerships with Kwanlin Dün First Nation and Ta'an Kwach'an Council began to change that.

One of the big benefits Wren sees in getting more Indigenous kids into the camps is they get to experience their culture being honoured, to feel pride in their lineage and ancestors. They see their Elders treated as knowledgeable guests, receiving attention and respect.

For Rivers to Ridges, one way reconciliation can start is by making it possible for non-Indigenous children to interact with Indigenous people and First Nations ways of being, knowing and doing that they may not be aware of or exposed to. It begins with forming relationships and then tending to them. "Relationships that lead to respect, reciprocity. Relationships that influence how young people walk on and use the land," says Wren.

"For some non-Indigenous kids, even just the concept of being on Indigenous land opens a starting point on a path towards reconciliation. How it ends, we don't know yet. As leaders, we are always learning."

Photo credit: Rivers to Ridges

Partnerships

Fish first

Lea Pigage and **Travis Ritchie** are biologists.

Sure, Lea happens to be Project Manager for Yukon Energy's Planning and Regulatory Affairs and Travis is Manager of Environment, Assessment and Licensing. But what really animates them is biology, specifically as it relates to the passage of Chinook salmon through the Whitehorse Rapids Fish Ladder. What really got their attention in 2021 were the results of a multi-year salmon migration study of the upper Yukon River.

Chinook salmon play a major role in the history, diet, culture and way of life of First Nations people in the Southern Lakes region. In 2017, the Government of Carcross/Tagish First Nation (GC/TFN) provided support for the Canadian Wildlife Federation (CWF) to conduct a study on the movement of Chinook salmon around and through the Whitehorse Fish Ladder. This turned into a collaborative effort among GC/TFN, CWF and the University of Ottawa, with field support from Kwanlin Dün First Nation (KDFN), Ta'an Kwäch'än Council (TKC), GC/TFN and Big Fish Little Fish Consulting. Yukon Energy provided field and financial support for the 2017–2020 research as well.

Their report concluded that: *Although sample sizes remain modest, evidence from three years of sampling indicates that passage efficiency in the Whitehorse Rapids Fish Ladder is low. Findings from this work may help to inform design and operational changes of the facility to improve salmon passage.*

And that's when the KDFN, TKC and GC/TFN met with Yukon Energy to see if there were ways to improve fish passage rates through the Fish Ladder, and to look at the Whitehorse Rapids Fish Hatchery to see if it is effective as it could be at keeping wild Chinook healthy. From here the Whitehorse Rapids Fish Ladder/Hatchery Technical Working Group was formed. The working group consists of representatives from Yukon Energy, the GC/TFN, TKC and KDFN.

"We have heard that the First Nations governments are concerned for the salmon and have been since the dam was built in 1957–58," says Lea.

The group's overall focus is working together to improve fish passage through the Whitehorse Fish Ladder. At its first meeting in November, 2021, it identified three goals.

1. Improve fish passage through the ladder.
2. Ensure the hatchery is doing the best it can for wild Chinook.
3. Improve collaboration between Yukon Energy and First Nations governments – "Sharing information together as a way of working together."

The goal for First Nations partners in the working group is stated even more directly: "Fish first. What's the best way to get as many as possible through the Fish Ladder, to their spawning grounds, and to get juvenile fish back out to the ocean?"

To reach its goals, the working group established a set of guiding principles to guide how they work together and broke the work down into three aspects.

1. Implement short-term Fish Ladder improvements.
2. Assess the effectiveness of the Fish Ladder.
3. Assess the effectiveness of the hatchery.

To address the first aspect, the group proposes:

- Installing a camera monitoring system as a way of monitoring and counting salmon;
- Keeping the ladder open 24 hours a day to facilitate fish movement; and
- Having First Nations representation in staffing the Fish Ladder and regular First Nations monitoring visits.

To address the second aspect, the group developed a Statement of Work for a technical assessment of the Fish Ladder, looking at both hydraulic and biologic factors. A contract for the work has been awarded to an eco-hydraulics assessment team consisting of Morrison Hershfield Engineering and Environmental Dynamics Consulting.

To address the third aspect, the working group is developing a Scope of Work to study the effectiveness of the fish hatchery and are working on procuring consultants for that work.

The Whitehorse Rapids Fish Ladder/Hatchery Technical Working Group is focused on both western scientific thinking and Indigenous world views – First Nations ways of knowing, doing and being.

"The collaborative approach that the Technical Working Group has taken centers on meaningful input and contribution from all parties – what can we do to help improve salmon migration?" says Pigage.

The key thing about this project is about putting fish first so that they can be here for future generations.

management discussion & analysis

Core Business and Strategy

Our business is the generation and transmission of electrical energy to most of Yukon. We strive for energy production that is sustainable, reliable and cost-effective. Our primary source of power comes from our legacy hydro assets and our goal is to minimize the use of non-renewable sources due to higher variable cost and environmental impacts.

Yukon Energy's strategy is based on the following key strategic pillars.

1. Sustainability

Yukon Energy is committed to the principles of sustainability in all our business practices, with the objective of protecting and enhancing Yukon's human and natural resources. We developed a Sustainability Policy in 2017 and were awarded the "Sustainable Electricity Company" designation by Electricity Canada, formerly known as the Canadian Electricity Association (CEA), in 2017. In terms of the development of new energy resources, we are committed to developing renewable resources while recognizing the limitations of certain forms of renewable generation in meeting the energy and capacity needs of Yukon's isolated grid. Thermal generation will continue to play an important role in meeting peak electricity demand cost effectively and providing insurance against contingent events such as drought and outages of key hydro facilities. We apply a social cost of carbon to the economics of future thermal generation resources in order to level the playing field between renewable and fossil fuel options when planning new resource investments. We periodically review long-term load forecasts and options for meeting this forecast through a comprehensive resource planning exercise. This process was last completed in 2020 when we published our 10-Year Renewable Electricity Plan which has been supported by all three government political parties in Yukon.

2. First Nations relationships

Yukon Energy is committed to active engagement with Yukon First Nations, striving to meet the spirit and intent of Land Claims obligations. We recognize First Nations governments as decision bodies and potential energy proponents, partners and investors. We seek to leverage our ongoing business operations and future project development work to create opportunities for economic, social and cultural development for Yukon First Nations. Key First Nations initiatives include project-specific agreements, and our First Nations employment and procurement policies. We are pursuing certification under the Aboriginal Business Council's Progressive Aboriginal Relations (PAR) program to manage and benchmark our First Nations engagement program.

3. Disciplined financial management

Given the rate pressures faced by Yukon electricity customers and the prospect for future rate increases driven by Yukon Energy's capital investment needs, disciplined financial management of our operating and project-related business is essential. We are also committed to continuous improvement as a management philosophy to drive sustained improvements in our operational performance and efficiency.

4. Rigorous and proactive planning

Yukon Energy applies industry best practices and processes for the planning of future capital investments required to sustain the Corporation's aging infrastructure and address growing demand for energy and capacity. Rigorous planning of future investments is required to optimize and prioritize capital expenditures, accounting for the financial constraints within which we operate. Key business processes that support these planning activities include Integrated Resource Planning and Asset Management. We have developed and annually update our five-year capital plan, including investments required to sustain existing assets and meet future growth as a key tool to document and communicate our longer-term capital needs.

5. Stakeholder and employee engagement

As a public utility, Yukon Energy is committed to broadly engaging with stakeholders during the planning of new projects and initiatives, and to incorporate to the extent possible, the preferences of stakeholders in those plans. This engagement is essential to securing social license for corporate initiatives, while also balancing the obligations of Yukon Energy to its shareholder and its primary regulators (the Yukon Utilities Board and the Yukon Water Board). In addition, our employees are critical to the company's success. Maintaining a safe, strong and engaged workforce capable of executing our ambitious plans remains a key strategic priority.

Capability to Deliver Results

In order to deliver on our strategic goals and achieve planned results, Yukon Energy maximizes the use of available resources while considering risks and impacts to stakeholders. These resources include leadership, labour force, working capital, systems and processes, liquidity, and capital resources.

We continue to develop human resources policies to adapt to our seasoned workforce and changing conditions in the workplace.

We monitor and forecast our cash and financial strength on an ongoing basis, including current and future projections. We expect to require cash to finance our capital projects in 2022 and are working towards obtaining the necessary funding.

Through established policies and procedures, Yukon Energy maintains a capital structure ratio of 60% long-term debt and 40% equity.

We continually monitor and evaluate the condition of our assets and allocate a material portion of our capital budget for maintenance of these assets, thereby ensuring reliability of service to Yukoners.

We make it a priority to maintain and improve our key relationships with Yukoners including the Yukon government, Yukon Development Corporation, local First Nations governments, stakeholders, and our bankers; we hold long-term debt with TD Bank and our primary banking services are with CIBC.

Results

Net income for the 2021 fiscal year was $13.5 million, compared to net loss of $133,000 the previous year. The increase in net income was primarily due to increased revenues from the sale of power and reduced spending on operations and maintenance.

Revenue from the sale of power was $78.6 million, $7.7 million higher than the prior year due to an increase in consumption primarily from the industrial sector.

The regulated rate of return on equity (ROE) for 2021 is forecast to be approximately 9.0%, subject to final direction from the Yukon Utilities Board on our 2021 General Rate Application. This is up from 2.73% the prior year. The Yukon Utilities Board approved rate is 8.20%. The low ROE in 2020 reflects a corporate decision to not apply for higher rates while customers were dealing with the impacts of the global Covid-19 pandemic.

Outlook

Yukon Energy submitted a General Rate Application (GRA) for 2021 to afford us the opportunity to adjust rates to reflect our cost requirements and capital plans. The previous GRA was for the 2018 test year. The Yukon Utilities Board issued their initial decision about our 2021 GRA in March, 2022 with the final decision expected during the summer of 2022.

Net income for 2022 is forecast to increase to approximately $17 million due to an increase in sales of power of $2.7 million and an increase in interest rates providing for an unrealized gain on interest rate swaps. This is partially offset by increased fuel and operations and maintenance costs relating to increased load.

The forecast return for 2022 is 9.95%, 1.75% more than the ROE that we were approved in our 2021 GRA of 8.20%.

Current national and global economic conditions have created material challenges to our forecasting. In particular, the highest inflation in 30 years in Canada, rising interest rates, and supply chain issues will, and have, affected our ability to execute our plans.

Risk Management

Yukon Energy is exposed to numerous risks in providing service to our customers and achieving our strategic priorities. The impacts of these risks can range in scale from minor to catastrophic. We endeavor to manage all the risks we face on a cost-effective basis, considering the resources required to mitigate risks compared to the reduction in risk achieved. We have an enterprise risk management framework that provides the basis for consistently applying risk management practices.

We assess and update our top risks annually and develop treatment plans with the goal of reducing the residual risk exposure to an acceptable level. The progress of risk treatment plans and status of risk drivers are reviewed on a quarterly basis. The current top risks are highlighted below by their impact on our strategic priorities.

- **Generate reliable and renewable energy –** There are number of risks that can impact this priority including insufficient installed capacity, climate change, cyber security, and dam safety. Treatment plans include continued progress on long-term new supply projects.
- **Secure long-term sustainable financing –** Successfully managing financing risk is critical to achieving this priority. Mitigation efforts involve developing new funding models and improved project reporting. Project cost and timeline overrun risks are also related to this strategic priority.
- **Develop mutually beneficial First Nations partnerships –** Obtaining social license from First Nations governments as well as regulatory uncertainty about different investment models will play a role in the pursuit of this strategic priority. Risk treatment activities are focused on the signing of key agreements as well as the development of internal policies.
- **Achieve excellence in employee engagement –** Employee recruitment, retention, and labour shortage is the key risk related to this priority; however, the risk related to the health and safety of our employees also plays a role. Several recruitment and retention initiatives are being pursued to mitigate these risks.
- **Streamline and clarify governance –** This strategic priority is closely linked with government/shareholder risk. Ongoing and improved communication practices are crucial to successfully mitigating this risk.
- **Provide outstanding, reliable customer value –** Risks of key asset failure and system reliability as well as risks to obtaining social license, are key components of achieving this priority. These risks are mitigated through ongoing work on our asset management program along with timely and meaningful public engagement.

Key Performance Drivers

There are several performance drivers and key performance indicators that are critical to the successful implementation of our strategy and achievement of our goals. Below is an outline of four of our most important performance drivers.

Health and safety

Given the nature of our industry, we are firmly committed to putting the policies, practices and procedures in place to help ensure our staff return home safely each day.

Return on equity (ROE)

In the process of regulating and setting rates for Yukon Energy, the Yukon Utilities Board must ensure that the rates are sufficient to allow us to provide reliable electric service while maintaining the financial integrity of the utility, including a return on invested capital.

Workforce

A stable workforce is crucial for delivering services required to achieve our business objectives. We regularly monitor our vacancy and turnover rate to ensure that our staffing is at appropriate levels. We set our human resources policies to recruit and retain a competent workforce, provide opportunities for professional development, and perform succession planning.

Reliability of service

Reliability of service is one of our most important objectives. Improving reliability requires a long-term investment strategy and commitment. Trends in recent performance measures are compared against past results. Senior management reviews performance indicators and acts when actual performance deviates from forecast.

financial statements

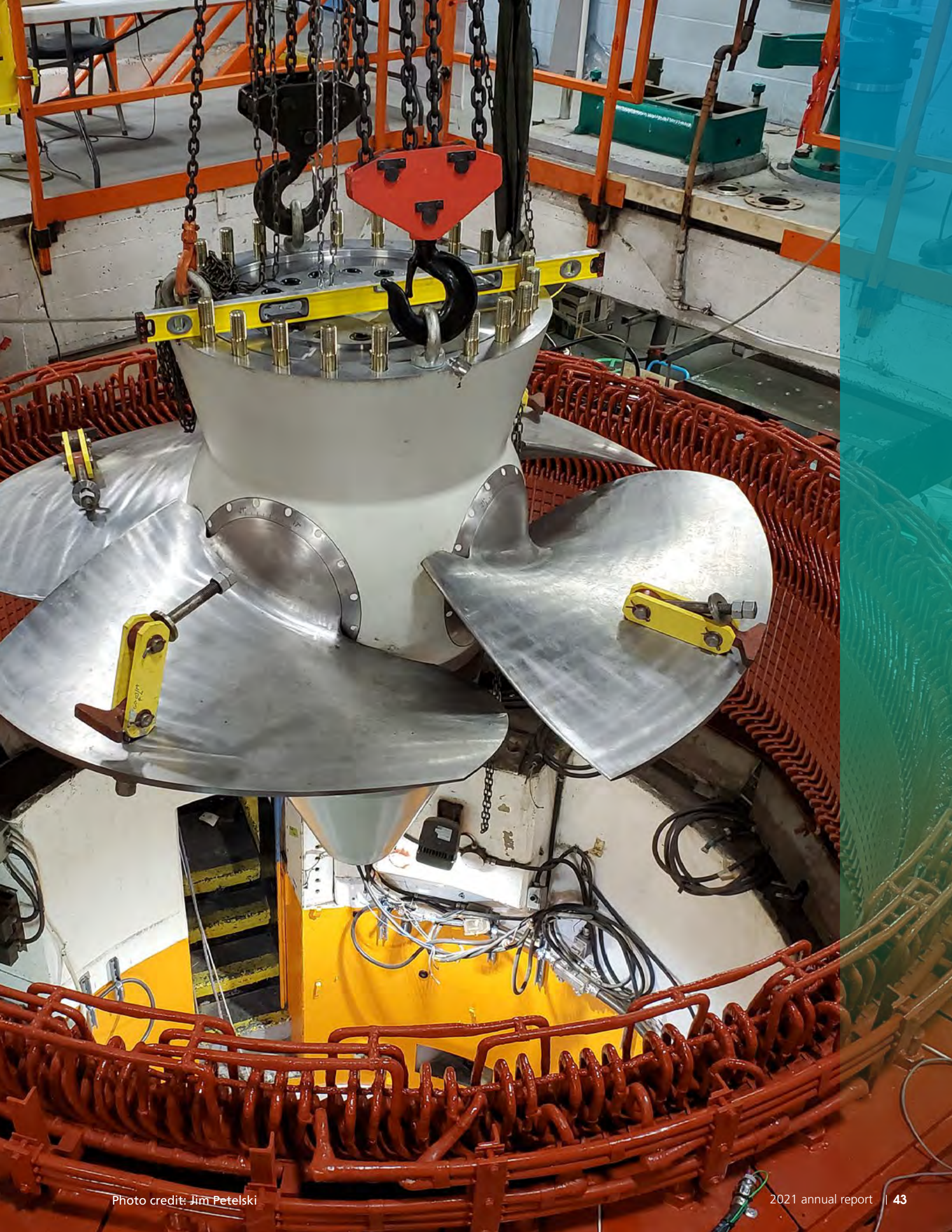


Photo credit: Jim Petelski

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Box 5920, Whitehorse
Yukon Y1A 6S7
yukonenergy.ca

May 11, 2022

Management's Responsibility for Financial Reporting

Management is responsible for the preparation of the financial statements and all other financial information relating to the Utility contained in this annual report. The financial statements have been prepared in conformity with International Financial Reporting Standards using methods appropriate for the industry in which the Utility operates and necessarily include some amounts that are based on informed judgments and best estimates of management. The financial information contained elsewhere in the annual report is consistent with that in the financial statements. The Auditor General of Canada is the external auditor of the Utility.

Management has established internal accounting control systems to meet its responsibilities for reliable and accurate reporting. These systems include policies and procedures, the careful selection and training of qualified personnel and an organizational structure that provides for the appropriate delegation of authority and segregation of responsibilities.

The Board of Directors, through its Audit Committee, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management and the independent auditor to discuss auditing and financial matters to assure that management is carrying out its responsibilities and to review the financial statements. The auditors have full and free access to the Audit Committee and management.

Andrew Hall
President and CEO

Ed Mollard
Vice President Finance, and Chief Financial Officer

Office of the Auditor General of Canada

Bureau du vérificateur général du Canada

INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of the Yukon Energy Corporation

Report on the Audit of the Financial Statements

Opinion

We have audited the financial statements of the Yukon Energy Corporation (the Corporation), which comprise the statement of financial position as at 31 December 2021, and the statement of operations and other comprehensive income, statement of changes in equity and statement of cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Corporation as at 31 December 2021, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRSs).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Corporation in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRSs, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Corporation's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Corporation or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Corporation's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Corporation's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Corporation's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Corporation to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Report on Compliance with Specified Authorities

Opinion

In conjunction with the audit of the financial statements, we have audited transactions of the Yukon Energy Corporation coming to our notice for compliance with specified authorities. The specified authorities against which compliance was audited are the *Public Utilities Act* and regulations, the *Business Corporations Act* and regulations, and the articles and by laws of the Yukon Energy Corporation.

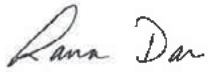
In our opinion, the transactions of the Yukon Energy Corporation that came to our notice during the audit of the financial statements have complied, in all material respects, with the specified authorities referred to above.

Responsibilities of Management for Compliance with Specified Authorities

Management is responsible for the Yukon Energy Corporation's compliance with the specified authorities named above, and for such internal control as management determines is necessary to enable the Yukon Energy Corporation to comply with the specified authorities.

Auditor's Responsibilities for the Audit of Compliance with Specified Authorities

Our audit responsibilities include planning and performing procedures to provide an audit opinion and reporting on whether the transactions coming to our notice during the audit of the financial statements are in compliance with the specified authorities referred to above.



Lana Dar, CPA, CA
Principal
for the Auditor General of Canada

Vancouver, Canada
11 May 2022

Yukon Energy Corporation
Statement of Financial Position
(in thousands of Canadian dollars)

As at	December 31 2021	December 31 2020
Assets		
Current		
Accounts receivable (Note 5)	$ 16,123	$ 25,589
Inventories (Note 6)	4,354	4,095
Prepaid expenses	1,323	1,443
	21,800	31,127
Non-current		
Property, plant and equipment (Note 7)	494,002	481,893
Intangible assets (Note 8)	18,895	17,436
Right-of-use assets (Note 9)	234	390
Total assets	**534,931**	530,846
Regulatory deferral account debit balances (Note 10)	31,804	34,613
Total assets and regulatory deferral account debit balances	**$ 566,735**	$ 565,459
Liabilities		
Current		
Bank indebtedness (Note 11)	$ 12 774	$ 31,929
Accounts payable and accrued liabilities (Note 12)	13,522	17,951
Construction financing (Note 13)	21,017	21,017
Current portion of deferred revenue (Note 17)	2,628	1,658
Current portion of lease liability (Note 9)	150	157
Current portion of long-term debt (Note 14)	6,537	6,280
	56,628	78,992
Non-current		
Post-employment benefits (Note 15)	4,252	9,071
Contributions in aid of construction (Note 16)	165,375	158,989
Deferred revenue (Note 17)	17,015	18,486
Lease liability (Note 9)	98	248
Derivative related liability (Note 26)	2,479	5,050
Long-term debt (Note 14)	167,037	166,056
Total liabilities	**412,884**	436,892
Equity		
Share capital		
Authorized: Unlimited number of a single class of shares with no par value		
Issued and fully paid: 3,900 shares	39,000	39 000
Contributed surplus	15,968	15 968
Retained earnings	82,684	64 249
Total equity	**137,652**	119,217
Total liabilities and equity	**550,536**	556,109
Regulatory deferral account credit balances (Note 10)	16,199	9,350
Total liabilities, equity and regulatory deferral account credit balances	**$ 566,735**	$ 565,459

Commitments and Contingencies (Notes 23 and 24)

The accompanying notes are an integral part of these financial statements.

Approved by the Board

_____, Chair

_____, Director

Yukon Energy Corporation
Statement of Operations and Other Comprehensive Income
(in thousands of Canadian dollars)

For the year ended December 31	2021	2020
Revenues		
Sales of power (Note 18)	$ 78,633	$ 70,907
Other (Note 19)	4,822	4,434
	83,455	75,341
Operating expenses		
Operations and maintenance (Note 20)	34,018	41,480
Depreciation and amortization (Notes 7, 8 and 9)	13,873	13,007
Administration (Note 21)	13,653	12,595
	61,544	67,082
Income before other income and other expenses	**21,911**	8,259
Other income		
Amortization of contributions in aid of construction (Note 16)	3,080	2,867
Allowance for funds used during construction	942	854
	4,022	3,721
Other expenses		
Interest on borrowings	5,316	5,680
Unrealized (gain) loss on interest rate swap (Note 26)	(2,571)	3,120
	2,745	8,800
Net income for the year before net movement in regulatory deferral account balances	**23,188**	3,180
Net movement in regulatory deferral account balances related to net income (Note 10 (d))	(9,658)	(3,313)
Net income (loss) for the year and net movement in regulatory deferral account balances	**13,530**	(133)
Other comprehensive income (loss) (Note 3 (o))		
Item that will not be reclassified to net income in subsequent periods		
Re-measurement of defined benefit pension plans (Note 15)	4,905	(1,214)
Total comprehensive income (loss) for the year	**$ 18,435**	$ (1,347)

The accompanying notes are an integral part of these financial statements.

Yukon Energy Corporation
Statement of Changes in Equity
(in thousands of Canadian dollars)

	Share Capital Number of shares	Share Capital $	Contributed surplus	Retained earnings	Accumulated other comprehensive income (loss)	Total
Balance at December 31, 2019	**3,900**	**$ 39,000**	**$ 14,600**	**$ 65,596**	**$ -**	**$ 119,196**
Net loss for the year and net movement in regulatory deferral account balances	-	-	-	(133)	-	(133)
Other comprehensive loss	-	-	-	-	(1,214)	(1,214)
Transfer of re-measurement of defined benefit pension plans to retained earnings	-	-	-	(1,214)	1,214	-
Conversion of debt (Note 13)	-	-	1,368	-	-	1,368
Balance at December 31, 2020	**3,900**	**$ 39,000**	**$ 15,968**	**$ 64,249**	**$ -**	**$ 119,217**
Net income for the year and net movement in regulatory deferral account balances	-	-	-	13,530	-	13,530
Other comprehensive income	-	-	-	-	4,905	4,905
Transfer of re-measurement of defined benefit pension plans to retained earnings	-	-	-	4,905	(4,905)	-
Balance at December 31, 2021	**3,900**	**$ 39,000**	**$ 15,968**	**$ 82,684**	**$ -**	**$ 137,652**

The accompanying notes are an integral part of these financial statements.

Yukon Energy Corporation
Statement of Cash Flows
(in thousands of Canadian dollars)

For the year ended December 31	2021	2020
Operating activities		
Cash receipts from customers	$ 79,086	$ 70,502
Cash receipts from contributions in aid of construction	19,029	1,418
Cash paid to suppliers	(35,487)	(36,266)
Cash paid to employees	(12,817)	(11,641)
Cash receipts from insurance claim settlement	3,762	-
Interest paid	(5,302)	(5,651)
Cash provided by operating activities	**48,271**	18,362
Financing activities		
Net advances from line of credit	15,878	-
Proceeds from long-term debt	7,659	4,801
Repayment of long-term debt	(6,421)	(6,079)
Lease payments	(168)	(167)
Cash provided by (used in) financing activities	**16,948**	(1,445)
Investing activities		
Additions to property, plant and equipment	(27,407)	(23,774)
Additions to intangible assets	(2,779)	(5,912)
Cash used in investing activities	**(30,186)**	(29,686)
Net increase (decrease) in cash	35,033	(12,769)
Cash, beginning of year	**(31,929)**	(19,160)
Cash, end of year (Note 11)	**$ 3,104**	$ (31,929)

The accompanying notes are an integral part of these financial statements.

December 31 2021

1. NATURE OF OPERATIONS

a) General

Yukon Energy Corporation ("the Utility") is incorporated under the Yukon *Business Corporations Act* and is a wholly-owned subsidiary of Yukon Development Corporation ("YDC" or "the Parent"), a corporation owned by the Yukon Government ("the Government" or "YG"). The Utility generates, transmits, distributes and sells electrical energy in the Yukon. The Utility is not subject to income taxes. The Utility's principal place of business is located at #2 Miles Canyon Road, Whitehorse, Yukon, Y1A 6S7.

The Utility is subject to overall regulation by the Yukon Utilities Board ("YUB") and specific regulation by the Yukon Water Board. Both boards are consolidated by the Government and as such are considered to be related parties for accounting purposes. Management has assessed that these boards operate independently from the Utility from a rate setting and operating perspective.

b) Rate regulation

The operations of the Utility are regulated by the YUB pursuant to the *Public Utilities Act*. The Utility is subject to a cost of service regulatory mechanism under which the YUB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment in rate base. There is no minimum requirement for the Utility to appear before the YUB to review rates. However, the Utility is not permitted to charge any rate for the supply of power that is not approved by an Order of the YUB. As actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

The regulatory hearing process used to establish or change rates typically begins when the Utility files a General Rate Application ("GRA") for its proposed electricity rate changes over the next one or two forecast years. The YUB must ensure that its decision, which fixes electricity rates, complies with appropriate principles of rate making, all relevant legislation including the *Public Utilities Act* and directives issued by the Government through Orders-In-Council ("OIC") that specify how the interests of the customer and Utility are to be balanced.

The YUB typically follows a two-stage decision process. In the first stage, the total costs that the Utility expects it will incur to provide electricity to its customers over the immediate future are reviewed and approved. The approval of these costs determines the total revenues the Utility is allowed to collect from its customers. It is the responsibility of the YUB to examine the legitimacy of three classes of costs:

- the costs to the Utility to run its operations and maintain its equipment (personnel and materials);
- the cost associated with the depreciation of all capital equipment; and
- the return on rate base (the borrowing costs related to borrowing that portion of rate base which is financed with debt plus the costs to provide a reasonable rate of return on that portion of rate base which is financed with equity).

The YUB assesses the prudency of costs added to rate base, which includes an allowance for funds used during construction ("AFUDC") charged to capital projects. The YUB also reviews the appropriateness of property, plant and equipment depreciation rates, which are periodically updated by the Utility through depreciation studies.

In the second stage, the YUB approves how the revenue will be raised. This stage essentially determines the electricity rates for the various customer classes in the Yukon: wholesale, general service, industrial, residential, sentinel and street lights and secondary sales. This process is guided mainly by requirements of OIC 1995/90 and can include a cost-of-service study which allocates the Utility's overall cost of service to the various customer classes on the basis of appropriate costing principles.

1. NATURE OF OPERATIONS - continued

b) Rate regulation - continued
In November 2020, the Utility filed a GRA for the year 2021 requesting approval of revenue requirement and related rate increases. The GRA requested a rate increase of 11.54%. An initial interim refundable rate rider (10.08%) was approved effective July 1, 2021. An additional interim refundable rate rider (9.25%) was approved effective December 1, 2021. The YUB issued an order in March, 2022 requiring the Utility to make changes and complete a Compliance Filing. The Utility submitted the Compliance Filing in April, 2022. The Utility expects the process to complete and a final order from the YUB in the second quarter of 2022.

These financial statements reflect the requested rate increase as the rate increase is for the period starting January 1, 2021. Refer to Note 4 Regulatory deferral account balances.

c) Water regulation
The Yukon Water Board ("YWB"), pursuant to the Yukon *Waters Act*, decides if and for how long the Utility will have water licences for the purposes of operating hydro generation stations in the Yukon. The licences will also indicate terms and conditions for the operation of these facilities. The current water licences have the following terms:

Aishihik Generating Station	February 28, 2023
Mayo Generating Station	December 31, 2025
Whitehorse Generating Station	December 31, 2025

d) Capital structure
The Utility's policy which has been approved by the YUB is to maintain a capital structure of 60% debt and 40% equity (Note 27). When dividends are declared to the Parent, they are typically loaned back in order to maintain this ratio during normal on-going operations.

2. BASIS OF PRESENTATION

a) Statement of compliance
These financial statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”).

These financial statements were authorized for issue by the Board of Directors on May 11, 2022.

b) Basis of measurement
The financial information included in the financial statements has been prepared on a historical cost basis, except for some financial instruments, as described in Note 3(f), which are measured at fair value.

3. SIGNIFICANT ACCOUNTING POLICIES

a) Revenue recognition
The Utility recognizes revenue from contracts where the right to consideration from a customer corresponds directly with the value to the customer of the Utility’s performance completed to date.

The majority of the Utility’s revenues from contracts with customers are derived from the generation, transmission, distribution, purchase and sales of electricity under the *Public Utilities Act*. The Utility evaluates whether the contracts it enters into meet the definition of a contract with a customer at the inception of the contract and ongoing basis if there is an indication of a significant change in facts and circumstances. Revenue is measured based on the transaction price specified in a contract with a customer. Revenue is recognized when control over a promised good or service is transferred to the customer and the Utility is entitled to consideration as a result of completion of the performance obligation.

3. SIGNIFICANT ACCOUNTING POLICIES - continued

The Utility recognizes a contract asset or deferred revenue for the contracts where the performance obligation has not been satisfied. Deferred revenue is recognized when the Utility receives consideration before the performance obligations have been satisfied. A contract asset is recorded when the Utility has rights to consideration for the completion of a performance obligation when that right is conditional on something other than the passage of time. The Utility recognizes unconditional rights to consideration separately as a trade receivable. Contract assets are evaluated at each reporting period to determine whether there is any objective evidence that they are impaired.

Electricity sales contracts are deemed to have a single performance obligation as the promise to transfer individual goods or services is not separately identifiable from other obligations in the contracts and therefore not distinct. These performance obligations are considered to be satisfied over time as electricity is delivered because of the continuous transfer of control to the customer. The method of revenue recognition for the electricity is an output method, which is based on the volume delivered to the customer.

The Utility's electricity sales are calculated based on the customer's usage of electricity during the period at the applicable published rates for each customer class. Electricity rates in the Yukon are set by the YUB. Electricity sales include an estimate of electricity deliveries not yet billed at period-end. The estimated unbilled revenue is based on several factors, including estimated consumption by customer, applicable customer rates and the number of days between the last billing date and the end of the period.

b) Translation of foreign currencies

The functional currency of the Utility is the Canadian Dollar. Revenue and expense items denominated in foreign currencies are translated at exchange rates prevailing during the period. Monetary assets and liabilities denominated in foreign currencies are translated at period-end exchange rates. Non-monetary assets and liabilities are translated at exchange rates in effect when the assets are acquired or the obligations are incurred. Foreign exchange gains and losses are reflected in net income for the period.

c) Allowance for funds used during construction

The cost of the Utility's property, plant and equipment and intangible assets includes an allowance for funds used during construction ("AFUDC"). The AFUDC rate is based on the Utility's weighted average cost of debt.

d) Cash

Cash is comprised of bank account balances (net of outstanding cheques).

e) Inventories

Inventories consist of materials and supplies, diesel fuel and liquefied natural gas. Inventories are carried at the lesser of weighted average cost and net realizable value. Cost includes all expenditures incurred in acquiring the items and bringing them to their existing condition and location. Critical spare parts are recognized in the Utility's property, plant and equipment.

The recoverable value of inventory considers its net realizable value, including required processing costs, and is impacted by estimates and assumptions on prices, quality, recovery and exchange rates. Obsolete materials and supplies are recorded at salvage value in the period when obsolescence is determined.

3. SIGNIFICANT ACCOUNTING POLICIES - continued

f) Financial instruments

Financial assets and financial liabilities are recognized on the Utility's Statement of Financial Position when the Utility becomes party to the contractual provisions of the instrument.

i) Financial assets

Cash and accounts receivable, plus any transaction costs that are directly attributable to the acquisition of the financial asset, are initially measured at fair value. Subsequent to initial recognition, cash is measured at amortized cost and accounts receivable are measured at amortized cost using the effective interest rate method less any impairment. The Utility's business model is to hold these assets to collect contractual cash flows.

A provision for impairment of accounts receivable is established applying the expected credit loss model based on all possible default events over the expected life of the financial asset. For trade accounts receivable, the Utility applies the simplified approach which requires expected lifetime losses to be recognized from initial recognition of the receivables. For other receivables, at the reporting date, if credit risk has increased significantly since initial recognition, the Utility measures the loss allowance at an amount equal to the lifetime expected credit losses, otherwise, if the credit risk has not increased significantly since initial recognition, the Utility measures the loss allowance at an amount equal to 12-month expected credit losses.

Significant financial difficulties of the debtor, probability that the debtor will enter into bankruptcy or require financial reorganization, and default or delinquency in payments are considered indicators that the related accounts receivable are impaired. The accounts receivable carrying amount is reduced through the use of an allowance account and the loss is recognized in net income. A financial asset is derecognized when the rights to receive cash flows from the asset have expired, or the Utility has transferred its rights to receive cash flows from the asset and has transferred substantially all the risk and rewards of the asset.

ii) Financial liabilities

Bank indebtedness, accounts payable and accrued liabilities, construction financing and long-term debt are initially measured at fair value less any transaction costs that are directly attributable to the issuance of the financial liability. Subsequent to initial recognition, these financial liabilities are measured at amortized cost using the effective interest method.

Transaction costs are presented as a reduction from the carrying value of the related debt and are amortized using the effective interest rate method over the terms of the debts to which they relate. Transaction costs include fees paid to agents, brokers and advisors but exclude debt discounts and lender financing costs.

Derivative financial instruments are financial contracts that derive their value from changes in an underlying variable. The Utility has entered into interest rate swaps to manage interest rate risk. The Utility's interest rate swap is classified as fair value through profit and loss and is thus recognized at fair value on the date the contract has been entered into with any subsequent realized and unrealized gains and losses recognized in net income during the period in which the fair value movement occurred.

A financial liability is derecognized when the obligation is discharged or cancelled, or expires.

3. SIGNIFICANT ACCOUNTING POLICIES - continued

g) Property, plant and equipment

Property, plant and equipment are carried at cost, less accumulated depreciation and any asset impairment charges. Cost includes the direct costs of acquisition and materials, direct labour, and, if applicable, an allocation of directly attributable overhead costs, AFUDC and any asset retirement costs associated with the property, plant and equipment.

AFUDC is applied to actual costs in work-in-progress less any contributions in aid of construction. For items of property, plant and equipment acquired prior to January 1, 2011, the AFUDC rate also included a regulatory cost of equity component as allowed by the YUB. Capitalization of AFUDC ceases when the asset being constructed is substantially ready for its intended purpose.

Assets under construction are recognized as construction work-in-progress until they are operational and available for use, at which time they are transferred to the applicable component of property, plant and equipment.

Depreciation is recognized in net income based on the straight-line method over the estimated useful life of each major component of property, plant and equipment.

The range of the estimated useful lives of the major classes and subclasses of property, plant and equipment is as follows:

Generation	
Hydroelectric plants	20 to 103 years
Thermal plants	12 to 72 years
Transmission	12 to 65 years
Distribution	16 to 55 years
Buildings	20 to 55 years
Transportation	8 to 25 years
Other equipment	5 to 20 years

Depreciation commences when an asset is available for use. The estimated useful lives of the assets are based upon depreciation studies conducted periodically by the Utility and any changes in the estimated useful lives are accounted for prospectively.

Major overhaul costs are capitalized and depreciated on a straight-line basis over the period of the expected useful life (until the next major overhaul) which varies from 2 to 10 years. Repairs and maintenance costs of property, plant and equipment are expensed as incurred unless they meet the criteria of a betterment.

3. SIGNIFICANT ACCOUNTING POLICIES - continued

h) Intangible assets

Intangible assets are carried at cost less accumulated amortization and any asset impairment charges. Cost includes the direct costs of acquisition and materials, direct labour, and, if applicable, an allocation of directly attributable overhead costs and AFUDC.

Amortization is recognized in net income on a straight-line basis over the estimated useful lives as follows:

Software	5 years
Deferred service costs	12 years
Financial software	10 years
Licensing costs	
Hydro generation	17 to 25 years
Diesel generation	3 years

The water licence for the Aishihik generating station received a 3 year extension. Costs associated with the 3 year extension are being amortized over 3 years (see Note 23).

i) Leases

At inception of a contract, the Utility assesses whether a contract is, or contains, a lease. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset. The Utility assesses whether:

- The contract involves the use of an identified asset;
- The Utility has the right to obtain substantially all of the economic benefits from use of the asset throughout the period of use; and
- The Utility has the right to direct the use of the asset.

At inception, the Utility allocates the consideration in the contract to each lease component on the basis of the relative stand-alone prices.

The Utility recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost, which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received. The Utility elected to exclude short-term leases with a term of twelve months or less as well as leases of low-value assets, and accounts for the lease payments associated with these leases as an expense on a straight-line basis over the lease term.

The right-of-use asset is subsequently depreciated using the straight-line method from the commencement date to the earlier of the useful life of the right-of-use asset or the end of the lease term. The estimated useful lives of right-of-use assets are determined on the same basis as those property, plant and equipment. In addition, the right-of-use asset is periodically reduced by impairment losses, if any, and adjusted for certain remeasurements of the lease liability. Right-of-use assets are tested for impairment in accordance with IAS 36, *Impairment of Assets*, and impairments are recorded in net income.

3. SIGNIFICANT ACCOUNTING POLICIES - continued

i) Leases - continued

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the Utility's incremental borrowing rate. Generally, the Utility uses its incremental borrowing rate as the discount rate. Subsequent to recognition, the lease liability is measured at amortized cost using the effective interest rate method. A lease liability is remeasured when there is a change in future lease payments arising mainly from a change in an index or rate, or if the Utility changes its assessment of whether it will exercise a renewal or termination option. When the lease liability is remeasured, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in net income if the carrying amount of the right-of-use assets has been reduced to zero.

j) Impairment of non-financial assets

Property, plant and equipment, and intangible assets with finite lives are reviewed for impairment on an annual basis if there is an indication that the carrying amount may not be recoverable. Impairment is assessed at the level of cash-generating units, which are identified as the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or group of assets.

When an impairment review is undertaken, the recoverable amount is assessed by reference to the higher of value in use and fair value less costs to sell ("FVLCS"). Value in use is the net present value of expected future cash flows of the relevant cash-generating unit in its current condition.

The best evidence of FVLCS is the value obtained from an active market or binding sale agreement. Where neither exists, FVLCS is based on the best information available to reflect the amount the Utility could receive for the cash-generating unit in an arm’s length transaction. This is often estimated using discounted cash flow techniques and where unobservable inputs are material to the measurement of the recoverable amount, the measurement is classified as level 3 in the fair value hierarchy. The cash flow forecasts for FVLCS purposes are based on management’s best estimates of expected future revenues and costs, including the future cash costs of production, capital expenditure, closure, restoration and environmental cleanup. For regulatory deferral account debit balances the impairment review focuses on whether the amount is considered collectible based on the expected cash flows from the rates approved by the YUB.

These determinations and their individual assumptions require that management make a decision based on the best available information at each reporting period. Changes in these assumptions may alter the results of impairment testing, impairment charges recognized in net income and the resulting carrying amounts of the assets.

3. SIGNIFICANT ACCOUNTING POLICIES - continued

k) Rate regulated accounting policies

Regulatory deferral accounts
Regulatory deferral accounts in these financial statements are accounted for differently than they would be in the absence of rate regulation. The Utility defers certain costs or revenues as regulatory deferral account debit balances or regulatory deferral account credit balances on the Statement of Financial Position and recognizes changes in the regulatory deferral account balances in the net movement in regulatory deferral account balances in the Statement of Operations and Other Comprehensive Income. The amounts recognized as regulatory deferral account balances are expected to be recovered or refunded in future rates, based on approvals by the YUB. The recovery or settlement of regulatory deferral account balances through future rates is impacted by demand risk and regulatory risks (e.g. potential future decisions of the YUB which could result in material adjustments to these regulatory deferral account debit balances and regulatory deferral account credit balances as described in Note 1(b)).

i) Regulatory deferral account debit balances
Regulatory deferral account debit balances represent costs which are expected to be recovered from customers in future periods through the rate-setting process. In the absence of rate regulation and the Utility's adoption of IFRS 14, *Regulatory Deferral Accounts*, such costs would be expensed as incurred.

ii) Regulatory deferral account credit balances
Regulatory deferral account credit balances represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate-setting process. In the absence of rate regulation and the Utility's adoption of IFRS 14, such amounts would be recorded in income as performance obligations are met.

Note 10 describes the individual regulatory deferral accounts, the Utility's related regulatory deferral and amortization policies and describes the related account activity in the relevant periods.

l) Provision for asset retirement obligations
The Utility has legal obligations related to the closure and restoration of property, plant and equipment, which includes the costs of dismantling, demolition of infrastructure and the removal of residual materials and remediation of the disturbed areas.

Where a reliable estimate of the present value of these obligations can be determined, the total retirement costs are recognized as a provision in the accounting period when the obligation arises. There is also a corresponding increase to property, plant and equipment upon recognition of the obligation. Management estimates its costs based on feasibility and engineering studies and assessments using current restoration standards and techniques.

3. SIGNIFICANT ACCOUNTING POLICIES - continued

m) Provision for environmental liabilities

Environmental liabilities consist of the estimated costs related to the remediation of environmentally contaminated sites. The Utility will accrue a provision when it has a present obligation as a result of a past event to remediate the contaminated site, it is expected that future economic benefits will be given up to settle the obligation, and a reliable estimate of the amount of the obligation can be made.

If the likelihood of the Utility's obligation to incur these costs is either not determinable or the amount of the obligation cannot be reliably estimated, the contingency is disclosed in the notes to the financial statements.

The Utility reviews its provision for environmental liabilities on an ongoing basis and any changes are recognized in net income for the current period.

n) Contributions in aid of construction

Certain property, plant and equipment additions are made with financial assistance from the Utility's Parent, the YG, or the Government of Canada. These contributions are deferred upon receipt and amortized to income on the basis of the life of the asset to which they relate.

o) Post-employment benefits and other comprehensive income

The Utility sponsors an employee defined benefit pension plan for employees joining the Utility before January 1, 2002. The Utility also sponsors an executive defined benefit pension plan and supplemental executive retirement plan for a former executive. Benefits provided are calculated based on length of pensionable service, pensionable salary at retirement age and negotiated rates. The Utility contributes amounts to the pension plans as recommended by an independent actuary.

For the defined benefit plans the cost of pension benefits is actuarially determined using the projected benefits method, prorated on service, and reflects management's best estimates of investment returns, wage and salary increases, and age at retirement. Re-measurements of the net defined benefit liability, including actuarial gains and losses and return on plan assets, are recognized in other comprehensive income ("OCI") and are not reclassified to net income in a subsequent period. The Utility's policy is to immediately transfer actuarial gains and losses recognized in OCI to retained earnings. The expected return on plan assets is based on the fair value of these assets.

Employees joining the Utility after January 1, 2002 are eligible for a defined contribution retirement plan and are not eligible to participate in the defined benefit pension plan. The Utility has no legal or constructive obligation to pay further contributions with respect to this plan. Contributions are recognized as an expense in the year when employees have rendered service and represent the obligation of the Utility.

4. SIGNIFICANT ACCOUNTING JUDGMENTS, ESTIMATES AND ASSUMPTIONS

The preparation of financial statements requires the use of judgment in applying accounting policies and in making critical accounting estimates that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of any contingent assets and liabilities. These judgments and estimates are based on management's best knowledge of the relevant facts and circumstances, having regard to previous experience, but actual results may differ from the amounts included in the financial statements. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which estimates are revised and in any future periods affected. Information about such judgments and estimates is contained in the accounting policies and/or the notes to the financial statements, and the key areas are summarized below.

Areas of significant judgment and estimates made by management in preparing these financial statements include:

Impairment of non-financial assets – Note 3(j)
An evaluation of whether or not an asset is impaired involves consideration of whether indicators of impairment exist. Management continually monitors the Utility's operations and makes judgments and assessments about conditions and events in order to conclude whether possible impairment exists.

Asset retirement obligations – Notes 3(l) and 24
In determining the present value of the obligation, the Utility must estimate the amount and timing of the future cash payments and then apply an appropriate risk-free interest rate. Any changes to the anticipated amounts or timing of future payments or risk-free interest rate can result in a change to the obligation.

Depreciation – Notes 3(g), 7 and 9
Significant components of property, plant and equipment are depreciated straight line over their estimated useful lives. Useful lives are determined based on current facts and past experience and the results of depreciation studies. While these useful life estimates are reviewed on a regular basis and depreciation calculations are revised accordingly, actual lives may differ from the estimates. As such, assets may continue in use after being fully depreciated, or may be retired or disposed of before being fully depreciated. The latter could result in additional depreciation expense in the period of disposition.

Intangible assets – Notes 3(h) and 8
In determining whether to recognize costs as intangible assets, management makes judgments about when the criteria for recognition are met. Changes to management's judgments would affect the carrying amount of the Utility's intangible assets and amortization recognition.

Post-employment benefits – Notes 3(o) and 15
The Utility accrues for its obligations under defined benefit pension plans using actuarial valuation methods and other assumptions to estimate the projected benefit obligation and the associated expense related to the current period. The key assumptions utilized include the long-term rate of inflation, rates of future compensation, liability discount rates and the expected return on plan assets. The Utility consults with qualified actuaries when setting the assumptions used to estimate benefit obligations. Actual rates could vary significantly from the assumptions and estimates used.

4. SIGNIFICANT ACCOUNTING JUDGMENTS, ESTIMATES AND ASSUMPTIONS - continued

Revenue – Notes 3(a) and 18
The Utility estimates usage not yet billed at year end, which is included in revenues from sales of power. This accrual is based on an assessment of unbilled electricity supplied to customers between the date of the last meter reading and the year end. Management applies judgment to the measurement of the estimated consumption. Significant judgments have also been made in determining the nature of the Utility's performance obligations, the appropriate process measure and the contract terms to be used in recognizing the related revenue.

Provisions and Contingencies – Notes 3(m) and 24
Management is required to make judgments to assess if the criteria for recognition of provisions and contingencies are met, in accordance with IAS 37, *Provisions, Contingent Liabilities and Contingent Assets*.

Key judgments are whether a present obligation exists and the probability of an outflow being required to settle that obligation. Key assumptions in measuring recognized provisions include the timing and amount of future payments and the discount rate applied in measuring the provision.

Where the Utility is defending certain lawsuits management must make judgments, estimates and assumptions about the final outcome, timing of trial activities and future costs as at the period end date. Management will obtain the advice of its external counsel in determining the likely outcome and estimating the expected obligations associated with these lawsuits; however, the ultimate outcome or settlement costs may differ from management's estimates.

Financial Instruments – Notes 3(f) and 26
The Utility enters into financial instrument arrangements which may require management to make judgments to determine if such arrangements are derivative instruments in their entirety or contain embedded derivatives, in accordance with IFRS 9, *Financial Instruments*. Key judgments are whether certain non-financial items are readily convertible to cash, whether similar contracts are routinely settled net in cash or delivery of the underlying commodity taken and then resold within a short period, and whether the value of a contract changes in response to a change in an underlying rate, price, index or other variable.

Regulatory deferral account balances – Notes 1(b), 3(k) and 10
The Utility accounts for its regulatory deferral accounts in accordance with IFRS 14 and the decisions of the YUB. As discussed in Note 1(b) the recovery of these balances will be determined by the YUB as part of the regulatory proceeding to approve the GRA. Management is required to make judgments as to the amounts that the YUB will approve the Utility to collect deferred costs through future rates.

Conversion of debt – Note 13
The Utility's policy is to maintain a capital structure of 60% debt and 40% equity as approved by the YUB (Note 27). Management is required to apply judgment in assessing whether amounts due to the Parent and subsequently converted are government contributions in accordance with IAS 20, *Accounting for Government Grants and Disclosure of Government Assistance* or are equity in nature.

5. ACCOUNTS RECEIVABLE

	December 31 2021	December 31 2020
Trade accounts receivable		
Wholesale energy sales	$ 6,171	$ 5,287
Retail energy sales	5,146	4,371
Due from related parties (Note 22)	1,256	10,978
Other	3,550	4,953
	$ 16,123	$ 25,589

Included in Accounts receivable - Other is an amount of $2,137,000 (2020 - $3,531,000) related to insurance proceeds.

At December 31, 2021, the aging of accounts receivable is as follows:

	Current	31 - 90 Days	Over 90 Days	Total
Accounts receivable	$ 14,606	$ 1,254	$ 273	$ 16,133
Allowance for doubtful accounts	-	-	(10)	(10)
	$ 14,606	$ 1,254	$ 263	$ 16,123

At December 31, 2020, the aging of accounts receivable is as follows:

	Current	31 - 90 Days	Over 90 Days	Total
Accounts receivable	$ 17,752	$ 1,091	$ 6,756	$ 25,599
Allowance for doubtful accounts	-	-	(10)	(10)
	$ 17,752	$ 1,091	$ 6,746	$ 25,589

A reconciliation of the beginning and ending amount of allowance for doubtful accounts is as follows:

	December 31 2021	December 31 2020
Allowance for doubtful accounts at beginning of year	$ (10)	$ (10)
Amounts written off as uncollectable	-	-
Allowance for doubtful accounts at end of year	$ (10)	$ (10)

6. INVENTORIES

	December 31 2021	December 31 2020
Materials and supplies	$ 3,488	$ 3,366
Diesel fuel	750	576
Liquefied natural gas	116	153
	$ 4,354	$ 4,095

7. PROPERTY, PLANT AND EQUIPMENT

A reconciliation of the changes in the carrying amount of property, plant and equipment is as follows:

	Generation	Transmission & Distribution	Land, Buildings & Other Equipment	Transportation	Construction Work-in Progress	Total
Cost:						
At December 31, 2019	$ 304,340	$ 199,053	$ 20,363	$ 5,172	$ 7,609	$ 536,537
Additions	-	-	-	-	25,591	25,591
Transfers	6,046	1,094	810	528	(8,478)	-
Disposals	(14)	-	(280)	-	-	(294)
At December 31, 2020	$ 310,372	$ 200,147	$ 20,893	$ 5,700	$ 24,722	$ 561,834
Additions	-	-	-	-	26,425	26,425
Transfers	15,284	31,074	981	-	(47,339)	-
Disposals	(880)	(1,095)	(114)	(216)	-	(2,305)
At December 31, 2021	$ 324,776	$ 230,126	$ 21,760	$ 5,484	$ 3,808	$ 585,954
Accumulated depreciation:						
At December 31, 2019	$ 32,459	$ 29,513	$ 4,687	$ 1,649	$ -	$ 68,308
Depreciation	6,390	4,381	782	360	-	11,913
Disposals	-	-	(280)	-	-	(280)
At December 31, 2020	$ 38,849	$ 33,894	$ 5,189	$ 2,009	$ -	$ 79,941
Depreciation	6,791	4,447	710	565	-	12,513
Disposals	(69)	(175)	(106)	(152)	-	(502)
At December 31, 2021	$ 45,571	$ 38,166	$ 5,793	$ 2,422	$ -	$ 91,952
Net book value:						
At December 31, 2020	$ 271,523	$ 166,253	$ 15,704	$ 3,691	$ 24,722	$ 481,893
At December 31, 2021	$ 279,205	$ 191,960	$ 15,967	$ 3,062	$ 3,808	$ 494,002

The total AFUDC capitalized for 2021 was $942,000 (2020 - $854,000). The AFUDC rate estimate for 2021 was 2.60% (2020 - 2.73%).

December 31 2021

8. INTANGIBLE ASSETS

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Software	Deferred Service Costs	Financial Software	Aishihik Water Licensing	Thermal and Water Licensing	Total
Cost:						
At December 31, 2019	$ 1,440	$ 443	$ 3,215	$ 6,275	$ 4,007	$ 15,380
Additions	246	-	2,972	2,269	425	5,912
At December 31, 2020	$ 1,686	$ 443	$ 6,187	$ 8,544	$ 4,432	$ 21,292
Additions	133	-	793	1,616	121	2,663
Disposals	(516)	-	-	-	-	(516)
At December 31, 2021	$ 1,303	$ 443	$ 6,980	$ 10,160	$ 4,553	$ 23,439
Accumulated amortization:						
At December 31, 2019	$ 673	$ 384	$ 1,702	$ -	$ 159	$ 2,918
Amortization	263	59	284	299	33	938
At December 31, 2020	$ 936	$ 443	$ 1,986	$ 299	$ 192	$ 3,856
Amortization	237	-	628	306	33	1,204
Disposals	(516)	-	-	-	-	(516)
At December 31, 2021	$ 657	$ 443	$ 2,614	$ 605	$ 225	$ 4,544
Net book value:						
At December 31, 2020	$ 750	$ -	$ 4,201	$ 8,245	$ 4,240	$ 17,436
At December 31, 2021	$ 646	$ -	$ 4,366	$ 9,555	$ 4,328	$ 18,895

Additions to Financial Software, Aishihik Water Licensing and Thermal and Water Licensing for 2021 and 2020 were almost exclusively internally generated. Additions to other categories were almost exclusively externally purchased.

9. LEASES

The Utility leases industrial land and building space. The lease terms typically run for five years. The right-of-use asset consists of land of $20,000 (2020 - $54,000) and building of $214,000 (2020 - $336,000).

	December 31 2021	December 31 2020
Right-of-use asset		
As at January 1	$ 390	$ 546
Depreciation expense	(156)	(156)
As at December 31	$ 234	$ 390
Lease liabilities		
Lease liabilities	$ 248	$ 405
Less current portion	150	157
Non-current portion	$ 98	$ 248
Maturity analysis		
Less than one year	$ 156	$ 168
One to five years	99	255
More than five years	-	-
Total undiscounted lease liabilities	$ 255	$ 423
Amounts recognized in net income		
Depreciation expense on right-of-use assets	$ (156)	$ (156)
Interest expense on lease liabilities	$ (11)	$ (16)
Expense relating to short-term leases	$ (3,946)	$ (2,315)

December 31 2021

10. REGULATORY ACCOUNTS

a) Regulatory deferral account debit balances

	Feasibility Studies (i)	Regulatory Costs (ii)	Dam Safety (iii)	Deferred Overhauls (iv)	Uninsured Losses (v)	Fuel Price Adjustment (vi)	Subtotal see next page
Cost:							
At December 31, 2019	$ 23,707	$ 4,715	$ 148	$ 2,768	$ 1,638	$ 1,639	$ 34,615
Costs incurred	1,064	4,755	174	-	4,764	-	10,757
Regulatory provision	-	(199)	-	-	(267)	3,485	3,019
Disposals	(1)	(1,981)	-	-	-	(2,867)	(4,849)
Contributions received/receivable	-	(539)	-	-	(3,531)	-	(4,070)
At December 31, 2020	$ 24,770	$ 6,751	$ 322	$ 2,768	$ 2,604	$ 2,257	$ 39,472
Costs incurred	1,343	1,789	81	-	3,654	-	6,867
Regulatory provision	-	-	-	-	(411)	1,557	1,146
Disposals	(4,450)	(598)	(148)	-	(104)	(2,491)	(7,791)
Contributions received/receivable	-	(279)	-	-	(2,737)	-	(3,016)
At December 31, 2021	$ 21,663	$ 7,663	255	$ 2,768	$ 3,006	$ 1,323	$ 36,678
Accumulated amortization:							
At December 31, 2019	$ 6,866	$ 1,223	$ 89	$ 683	$ 636	$ -	$ 9,497
Amortization	1,928	485	29	587	212	-	3,241
Disposals	(1)	(652)	-	-	-	-	(653)
At December 31, 2020	$ 8,793	$ 1,056	$ 118	$ 1,270	$ 848	$ -	$ 12,085
Amortization	2,168	414	55	581	204	-	3,422
Disposals	(4,450)	(598)	(148)	-	-	-	(5,196)
At December 31, 2021	$ 6,511	$ 872	$ 25	$ 1,851	$ 1,052	$ -	$ 10,311
Net book value:							
At December 31, 2020	$ 15,977	$ 5,695	$ 204	$ 1,498	$ 1,756	$ 2,257	$ 27,387
At December 31, 2021	$ 15,152	$ 6,791	$ 230	$ 917	$ 1,954	$ 1,323	$ 26,367
Net increase (decrease) in regulatory deferral account debit balances (which are recognized in the net movement in regulatory deferral account balances related to net income on the Statement of Operations and Other Comprehensive Income):							
December 31, 2020	$ (864)	$ 2,203	$ 145	$ (587)	$ 754	$ 618	$ 2,269
December 31, 2021	$ (825)	$ 1,096	$ 26	$ (581)	$ 198	$ (934)	$ (1,020)
Remaining recovery years							
At December 31, 2020	1 to 6 years	1 to 33 years	1 year	1 to 6 years	Indeterminate	1 year	
At December 31, 2021	1 to 5 years	1 to 32 years	5 years	1 to 5 years	Indeterminate	1 year	
Absent rate regulation, net income for the year and net movement in regulatory deferral account balances on the Statement of Operations and Other Comprehensive Income would increase (decrease) by:							
December 31, 2020	$ 864	$ (2,203)	$ (145)	$ 587	$ (754)	$ (618)	$ (2,269)
December 31, 2021	$ 825	$ (1,096)	$ (26)	$ 581	$ (198)	$ 934	$ 1,020

10. REGULATORY ACCOUNTS - continued

	Carry Forward	Vegetation Management (vii)	2017/18 GRA (viii)	2021 GRA (ix)	Total
Cost:					
At December 31, 2019	$ 34,615	$ 2,216	$ 12,320	$ -	$ 49,151
Costs incurred	10,757	-	-	-	10,757
Regulatory provision	3,019	-	-	-	3,019
Disposals	(4,849)	-	(6,423)	-	(11,272)
Contributions received	(4,070)	-	-	-	(4,070)
At December 31, 2020	$ 39,472	$ 2,216	$ 5,897	$ -	$ 47,585
Costs incurred	6,867	-	-	-	6,867
Regulatory provision	1,146	-	-	8,779	9,925
Disposals	(7,791)	-	(5,897)	(4,449)	(18,137)
Contributions received	(3,016)	-	-	-	(3,016)
At December 31, 2021	$ 36,678	$ 2,216	$ -	$ 4,330	$ 43,224
Accumulated amortization:					
At December 31, 2019	$ 9,497	$ 666	$ -	$ -	$ 10,163
Amortization	3,241	221	6,423	-	9,885
Disposals	(653)	-	(6,423)	-	(7,076)
At December 31, 2020	$ 12,085	$ 887	$ -	$ -	$ 12,972
Amortization	3,422	222	5,897	4,449	13,990
Disposals	(5,196)	-	(5,897)	(4,449)	(15,542)
At December 31, 2021	$ 10,311	$ 1,109	$ -	$ -	$ 11,420
Net book value:					
At December 31, 2020	$ 27,387	$ 1,329	$ 5,897	$ -	$ 34,613
At December 31, 2021	$ 26,367	$ 1,107	$ -	$ 4,330	$ 31,804
Net increase (decrease) in regulatory deferral account debit balances (which are recognized in the net movement in regulatory deferral account balances on the Statement of Operations and Other Comprehensive Income):					
December 31, 2020	$ 2,269	$ (221)	$ (6,423)	$ -	$ (4,375)
December 31, 2021	$ (1,020)	$ (222)	$ (5,897)	$ 4,330	$ (2,809)
Remaining recovery years					
At December 31, 2020		6 years	1 year		
At December 31, 2021		5 years	0 years	2 years	
Absent rate regulation, net income for the year and net movement in regulatory deferral account balances on the Statement of Operations and Other Comprehensive Income would increase (decrease) by:					
December 31, 2020	$ (2,269)	$ 221	$ 6,423	$ -	$ 4,375
December 31, 2021	$ 1,020	$ 222	$ 5,897	$ (4,330)	$ 2,809

(i) Feasibility studies and infrastructure planning

The Utility undertakes certain studies to determine the feasibility of a range of projects and infrastructure proposals. While in progress, the costs of these studies are deferred within this account. The Utility is directed to defer and amortize the costs over terms (between five and ten years) at the discretion of the YUB. In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

10. REGULATORY ACCOUNTS - continued

(ii) Regulatory costs
These costs are associated with the YUB regulatory proceedings. The costs consist primarily of various rate and project review proceedings but also include resource plans, hearing costs from before 2012 and demand side management costs (consumer energy conservation program). The Utility is directed to defer and amortize the costs over terms at the discretion of the YUB. In February 2021, the Utility lost an appeal relating to a decision by the YUB denying certain Demand Side Management costs. As a result, the Utility wrote off costs with a net book value as at December 31, 2020 of $1,329,000. The regulatory provision for the year reflects an amount transferred of $0 (2020 - $199,000) to the regulatory deferral account credit balance class Hearing Reserve (see Note 10(b)(ii)). In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

(iii) Dam safety review
The Utility has a program of conducting safety reviews of its dams in accordance with standards set by the Canadian Dam Association. External consultants are hired every five years with intermittent costs incurred in the interim periods. These costs are being amortized over five years. In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

(iv) Deferred overhauls
YUB Order 2013-01 restricted inclusion of property, plant and equipment overhaul depreciation expense in rates charged to customers until the Utility comes before the YUB for a prudence review. As such, starting in 2013 the Utility deferred depreciation expense related to overhauls. In 2017, the Utility came before the YUB for a prudence review and began to recognize these deferred depreciation amounts. In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

(v) Uninsured losses
Uninsured losses is an account maintained to address uninsured and uninsurable losses as well as the deductible portion of insured losses. The account is maintained through an annual provision and collected through customer rates. There is an annual regulatory provision of $411,000 (2020 - $267,000) and amortization of the forecast 2020 accumulated balance of $2,048,000 (2020 - 2016 accumulated balance of $1,059,000) over ten years ($205,000 per year; 2020 - $212,000 per year over five years). Costs incurred during 2021 of $3,654,000 (2020 - $4,764,000) include $2,445,000 (2020 - $3,631,000) of costs due to repairs required at the WH1 and WH2 penstocks. During 2021 the Utility recorded $2,368,000 of penstock insurance proceeds and expects to recover a significant portion of the balance of costs from insurance proceeds in 2022 (see Note 19). In the absence of rate regulation, IFRS requires these costs to be expensed as incurred and the expected insurance proceeds recognized as revenue.

(vi) Fuel price adjustment
OIC 1995/90 directs the YUB to permit the Utility to adjust electricity rates to reflect fluctuations in the price of diesel fuel. The amount by which actual fuel prices vary from the long-term average prices is deferred and recovered from or refunded to customers in a future period through Rider F. In 2017 the Utility updated the long-term average cost to better reflect current market conditions. For all of 2019 Rider F was a refund of 0.011 cents per kWh. For the period January 1, 2020 through October 31, 2020 Rider F was a charge to customers of 0.970 cents per kWh. For the period November 1, 2020 through June 30, 2021 the charge increased to 1.371 cents per kWh. Effective July 1, 2021, the charge was reduced to 0.000 cents per kWh. In the absence of rate regulation, IFRS requires these costs to be expensed as incurred and revenues be recognized as earned.

10. REGULATORY ACCOUNTS - continued

(vii) Vegetation management
Prior to 2017, the Utility was deferring annual brushing costs in excess of a prescribed maximum annual amount based on a review of prior year brushing costs. In 2017, the Utility established a vegetation management policy and as a result of expected annual costs, deferral is no longer required. The Utility completes a full cycle of all of its brushing requirements every 10 years and is amortizing previously deferred costs over a 10 year period. In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

(viii) 2017/18 GRA
The Utility recognizes a regulatory deferral account debit balance when the Utility has the right, as a result of the actual or expected actions of the rate regulator, to increase rates in future periods in order to recover its allowable costs plus return on rate base, as described in Note 1(b). The amount recognized represents the amount approved by the YUB in November 2019, less amounts subsequently received from customers. At December 31, 2021 the amount was fully collected.

(ix) 2021 GRA
The Utility recognizes a regulatory deferral account debit balance when the Utility has the right, as a result of the actual or expected actions of the rate regulator, to increase rates in future periods in order to recover its allowable costs plus return on rate base, as described in Note 1(b). The amount recognized represents management's best estimates of revenues for rates to be approved by the YUB less amounts received from customers. The ending balance at December 31 comprises the Utility's remaining revenue shortfall to be collected from customers in future years.

(xi) Deferred gains and losses
Deferred gains and losses represent amounts from disposals of property, plant and equipment that have or will be submitted for approval by the YUB to be deferred. There are no deferred gains or losses during any of the reporting years.

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10. REGULATORY ACCOUNTS - continued

b) Regulatory deferral account credit balances

	Deferred Insurance Proceeds (i)	Hearing Reserve (ii)	Low Water Reserve Fund (iii)	Future Removal and Site Restoration (iv)	Contracts with Customers (v)	McQuesten Substation (vi)	Total
Cost:							
At December 31, 2019	$ 11,602	$ 682	$ (2,013)	$ 2,791	$ 5,095	$ -	$ 18,157
Cost incurred	-	(137)	(488)	(52)	-	-	(677)
Regulatory provision	-	51	-	-	31	-	82
Cash received	-	-	(11)	-	-	-	(11)
Cash refunded	-	-	1	-	-	-	1
At December 31, 2020	$ 11,602	$ 596	$ (2,511)	$ 2,739	$ 5,126	$ -	$ 17,552
Cost incurred	-	(101)	-	-	-	-	(101)
Regulatory provision	-	250	5,288	-	30	1,834	7,402
Cash received	-	-	-	-	-	-	-
Cash refunded	-	-	5	-	-	-	5
At December 31, 2021	$ 11,602	$ 745	$ 2,782	$ 2,739	$ 5,156	$ 1,834	$ 24,858
Accumulated amortization:							
At December 31, 2019	$ 7,162	$ 583	$ -	$ -	$ -	$ -	$ 7,745
Amortization	262	195	-	-	-	-	457
Disposals	-	-	-	-	-	-	-
At December 31, 2020	$ 7,424	$ 778	$ -	$ -	$ -	$ -	$ 8,202
Amortization	262	195	-	-	-	-	457
Disposals	-	-	-	-	-	-	-
At December 31, 2021	$ 7,686	$ 973	$ -	$ -	$ -	$ -	$ 8,659
Net book value:							
At December 31, 2020	$ 4,178	$ (182)	$ (2,511)	$ 2,739	$ 5,126	$ -	$ 9,350
At December 31, 2021	$ 3,916	$ (228)	$ 2,782	$ 2,739	$ 5,156	$ 1,834	$ 16,199
Net (increase) decrease in regulatory deferral account credit balances (which are recognized in the net movement of regulatory deferral account balances related to net income on the Statement of Operations and Other Comprehensive Income):							
December 31, 2020	$ 262	$ 281	$ 498	$ 52	$ (31)	$ -	$ 1,062
December 31, 2021	$ 262	$ 46	$ (5,293)	$ -	$ (30)	$ (1,834)	$ (6,849)
Remaining recovery years							
At December 31, 2020	16 years	Indeterminate	Indeterminate	Indeterminate	47 years	53 years	
At December 31, 2021	15 years	Indeterminate	Indeterminate	Indeterminate	46 years	52 years	
Absent rate regulation, net income for the year end and net movement in regulatory deferral account balances on the Statement of Operations and Other Comprehensive Income would increase (decrease) by:							
December 31, 2020	$ (262)	$ (281)	$ (498)	$ (52)	$ 31	$ -	$ (1,062)
December 31, 2021	$ (262)	$ (46)	$ 5,293	$ -	$ 30	$ 1,834	$ 6,849

10. REGULATORY ACCOUNTS - continued

(i) Deferred insurance proceeds
The deferred insurance proceeds represents a gain on fire insurance proceeds related to a fire at the Whitehorse Rapids Generating Station in 1997 which is being amortized to income at the same rate as depreciation of the related replacement assets. In the absence of rate regulation, IFRS requires the gain to have been fully recognized as income in the year received.

(ii) Hearing reserve
The Utility has established a deferral account for future regulatory hearing costs. In 2017 the Utility adjusted the annual provision and recognition of the accumulated balance to more accurately reflect expected hearing costs. The regulatory provision for the year reflects an annual provision of $250,000 (2020 - $250,000) less $0 (2020 - $199,000) of costs transferred from the regulatory deferral account debit balance class Regulatory Costs (see Note 10(a)(ii)). In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

(iii) Low Water Reserve Fund
The Low Water Reserve Account ("LWRF") was established by YUB Order 2018-10. The LWRF is used to protect the Utility and ratepayers for costs associated with variability in thermal generation required when there is a thermal cost variance due solely to water-related hydro generation variances from YUB approved GRA forecasts. YUB Order 2019-08 amended how the LWRF is calculated.

The LWRF attracts interest based upon short/intermediate term bond rates. Any negative balance attracts interest at the lowest short-term bond rates available to the Utility through its line of credit. The Utility is required to file annual reports with the YUB on the LWRF's activity.

In accordance with YUB Order 2015-01, the Utility defers recognition of the additional amounts collected from rate payers when the cost of thermal consumed in the period is less than the long-term average thermal requirements estimated for the actual annual generation load. These deferred amounts are recognized as revenue in the period when the cost of thermal incurred for the period is greater than the long-term average thermal requirements and the reason for the shortfall is a shortage of water in the hydro system. There is a cap of +/- $16 million for the LWRF. If the balance falls outside of this range, the Utility is to make an application to the YUB requesting recovery or a refund to customers. YUB Order 2019-02 set the refund rider to 0.00 cents/kWh effective April 1, 2019.

In the absence of rate regulation, IFRS would require any amounts earned or incurred related to the LWRF to be included in the Utility's net income in the year incurred.

10. REGULATORY ACCOUNTS - continued

(iv) Future removal and site restoration costs
The Utility maintains a regulatory provision for future removal and site restoration related to property, plant and equipment, which is incremental to that required to be recognized as an asset retirement provision under IAS 37. The reserve has been established through amortization rates based upon depreciation studies conducted periodically by the Utility. As a result of YUB Order 2005-12, effective January 1, 2005, the provision is not to exceed the cumulative value of the provision at December 31, 2004 of $5,757,000.

Costs of dismantling capital assets, including site remediation, will be applied to this regulatory deferral account credit balance if they do not otherwise relate to an asset retirement provision. The period over which the provision will be reduced is dependent on the timing of future costs of demolishing, dismantling, tearing down, site restoration or otherwise disposing of the asset net of actual recoveries, and is therefore indeterminate. In the absence of rate regulation, IFRS requires these costs to be expensed or included in the gain or loss on disposal of the related property, plant and equipment, as applicable.

(v) Contracts with customers
Effective January 1, 2018 the Utility adopted IFRS 15, *Revenue from Contracts with Customers*. As a result of the impacts of IFRS 15, certain revenues are recognized in net income over a shorter period than allowed by the YUB for rate-setting purposes. The timing difference is reflected as a regulatory deferral account credit balance.

(vi) McQuesten Substation
YUB Order 2022-03 required the Utility to create a separate asset class for certain assets constructed at the McQuesten Substation relating to the Victoria Gold connection. These assets were required to be amortized over the mine life as opposed to the useful life of the assets. The timing difference is reflected as a regulatory deferral account credit balance.

(c) Regulatory account expenses

Regulatory account expenses represent costs incurred related to regulatory account debit balances of $6,867,000 (2020 - $10,757,000) and regulatory account credit balances of $101,000 (2020 - $677,000).

(d) Net movement in regulatory deferral account balances related to net income

Net movement in regulatory deferral account balances related to net income is $9,658,000 (2020 - $3,313,000) represents the adjustment to net income for the year before net movement in regulatory deferral account balances for the effects of rate regulation in accordance with IFRS 14. The net movement figure is comprised of a decrease of $2,809,000 for regulatory account debit balances and an increase of $6,849,000 for regulatory account credit balances for rate regulation compared to the amounts that are recognized under IFRS. The net movement figure for 2020 is comprised of an decrease of $4,375,000 for regulatory account debit balances and a $1,062,000 decrease for regulatory account credit balances respectively for rate regulation compared to the amounts that would be recorded under IFRS absent rate regulation.

11. BANK INDEBTEDNESS

By agreement the financial institution has a legally enforceable right to set off the outstanding balance under the line of credit by cash balances in other accounts with the same bank. The amount outstanding on the line of credit balance at year end was $15.9 million (2020 - $35.1 million). The Utility has cash balances with the same financial institution of $3.1 million (2020 - $3.1 million).

Due to changing circumstances, for the purposes of the statement of cash flows, the line of credit no longer forms part of the Corporation's cash management and instead is classified as financing activities. In the statement of cash flows, cash is comprised of:

	December 31 2021	December 31 2020
Bank balances	$ 3,104	$ 3,137
Line of credit	-	(35,066)
	$ 3,104	$ (31,929)

The Utility's bank indebtedness is comprised of:

	December 31 2021	December 31 2020
Bank balances	$ 3,104	$ 3,137
Line of credit	(15,878)	(35,066)
	$ (12,774)	$ (31,929)

12. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	December 31 2021	December 31 2020
Trade payables	$ 10,340	$ 15,143
Employee compensation	1,690	1,427
Due to related parties (Note 22)	1,216	1,117
Other	276	264
	$ 13,522	$ 17,951

13. CONSTRUCTION FINANCING

	December 31 2021	December 31 2020
Construction financing, due December 31, 2022 bearing interest at 1.50% approved to a maximum of $8.4 million	$ 8,400	$ -
Construction financing, due December 31, 2022 bearing interest at 1.50% approved to a maximum of $14 million	12,617	-
Construction financing, due December 31, 2021 bearing interest at 0.89% approved to a maximum of $8.4 million	-	8,400
Construction financing, due December 31, 2021 bearing interest at 0.89% approved to a maximum of $14 million	-	12,617
	$ 21,017	$ 21,017

Construction financing balances are monies advanced from the Parent to assist in the development of the Utility's infrastructure. Interest is payable annually at December 31 and at the maturity date.

During the year the Utility converted $0 (2020 - $1,368,000) of construction financing into contributed surplus from the Parent with no impact to cash flows. In addition, the Utility converted $0 (2020 - $3,959,000) of construction financing into long-term debt from the Parent with no impact on cash flows (see Note 14). The remaining prior year debt was extinguished and replaced with new debt with no impact on cash flows.

14. LONG-TERM DEBT

The Utility's long-term debt is summarized as follows:

	December 31 2021	December 31 2020
Yukon Development Corporation		
$77,723,273 term note bearing interest at 2.68% repayable in annual installments of $3,683,800 principal, plus accrued interest with the balance of $59,304,273 due December 31, 2024	$ 66,672	$ 70,355
$21,900,000 flexible term note bearing interest up to 5.46% repayable in annual installments of $336,923 principal, plus accrued interest with the balance of $8,423,078 due December 31, 2051 (i)	18,531	18,867
$5,505,000 term note bearing interest at 2.40% interest only payable annually, due December 31, 2039	5,505	5,505
$20,984,404 term note bearing interest at 2.21% repayable in annual installments of $839,376 principal, plus accrued interest with the balance due December 31, 2040	15,948	16,787
$12,136,000 term note bearing interest at 2.10% interest only payable annually, due December 31, 2041	12,136	12,136
$2,871,000 term note bearing interest at 2.90% interest only payable monthly, due June 30, 2044	2,871	2,871
$3,958,745 term note bearing interest at 1.56% interest only payable monthly, due June 30, 2025	3,959	3,959
TD Bank		
The Utility entered into an interest rate swap to convert the interest rate on the Bankers' Acceptances amounts from a variable interest rate based on the Bankers' Acceptances rates to a fixed rate of 2.06% per annum. Payable in monthly installments of $47,918 interest and principal with the balance due on September 28, 2035 (ii)	7,831	8,240
The Utility entered into an interest rate swap to convert the interest rate on the Bankers' Acceptance amounts from a variable interest rate based on the Bankers' Acceptance rates to a fixed rate of 3.40% per annum. Payable in monthly installments of $117,095 interest and principal with the balance due on August 23, 2043 (iii)	21,527	22,189
The Utility entered into an interest rate swap to convert the interest rate on the Bankers' Acceptance amounts from a variable interest rate based on the Bankers' Acceptance rates to a fixed rate of 2.64% per annum. Payable in monthly installments of $30,868 interest and principal with the balance due on July 14, 2044 (iv)	6,295	6,497
The Utility entered into an interest rate swap to convert the interest rate on the Bankers' Acceptance amounts from a variable interest rate based on the Bankers' Acceptance rates to a fixed rate of 2.06% per annum. Payable in monthly installments of $20,478 interest and principal with the balance due on November 4, 2045 (v)	4,640	4,789
The Utility entered into an interest rate swap to convert the interest rate on the Bankers' Acceptance amounts from a variable interest rate based on the Bankers' Acceptance rates to a fixed rate of 2.88% per annum. Payable in monthly installments of $35,853 interest and principal with the balance due on April 30, 2046 (vi)	7,518	-

14. LONG-TERM DEBT - continued

Carmacks Stewart First Nation Liability Long-term liability payable to several First Nations related to the building of the Carmacks Stewart Transmission Line. These are non-interest bearing, repayment terms not yet established	141	141
Long-term debt	173,574	172,336
Less current portion	6,537	6,280
	$ 167,037	$ 166,056

(i) $21,900,000 Flexible Term Note
The terms of the flexible term note provide for a maximum amount of interest payable within a calendar year, calculated based on the actual grid generation on the electrical grid system connected with the Mayo Hydro Enhancement Project. The amount of interest payable as a result of the interest rate exceeding the maximum interest payable will abate forever. The actual interest rate on this flexible note was 5.46% (2020 - 5.46%).

(ii) TD Bank Loan and 2.06% Interest Rate Swap
On December 28, 2012, the Utility entered into a loan and interest rate swap with TD Bank to arrange financing for the purpose of continuing to develop the electrical infrastructure in the Yukon. On September 11, 2020, the loan and interest rate swap was amended. The amendment changed the interest rate from 2.69% to 2.06% and the termination date from December 28, 2022 to September 28, 2035.

(iii) TD Bank Loan and 3.40% Interest Rate Swap
On August 23, 2018, the Utility entered into a loan and interest rate swap with TD Bank to arrange financing for the purpose of continuing to develop the electrical infrastructure in the Yukon. On September 11, 2020, the loan and interest rate swap was amended. The amendment changed the interest rate from 3.67% to 3.40% and the termination date from August 23, 2038 to August 23, 2043.

(iv) TD Bank Loan and 2.64% Interest Rate Swap
On July 15, 2019, the Utility entered into a loan and interest rate swap with TD Bank to arrange financing for the purpose of continuing to develop the electrical infrastructure in the Yukon. On September 11, 2020, the loan and interest rate swap was amended. The amendment changed the interest rate from 2.90 % to 2.64% and the termination date from July 14, 2039 to July 14, 2044.

(v) TD Bank Loan and 2.06% Interest Rate Swap
On November 4, 2020, the Utility entered into a loan and interest rate swap with TD Bank to arrange financing for the purpose of continuing to develop the electrical infrastructure in the Yukon. The interest rate swap matures November 4, 2045.

(vi) TD Bank Loan and 2.88% Interest Rate Swap
On April 26, 2021, the Utility entered into a loan and interest rate swap with TD Bank to arrange financing for the purpose of continuing to develop the electrical infrastructure in the Yukon. The interest rate swap matures April 30, 2046.

14. LONG-TERM DEBT - continued

Long-term debt repayment
Scheduled repayments for all long-term debt are as follows:

2022	6,537
2023	6,584
2024	62,253
2025	6,958
2026	3,050
Thereafter	88,192
	$ 173,574

The change in long-term debt arising from financing activities during the year related to principal repayments of $6,421,000 (2020 - $6,079,000) and the issuance of additional debt in the amount of $7,659,000 (2020 - $8,759,000).

Fair value
The fair value of long-term debt at December 31, 2021 is $179,328,000 (2020 - $186,554,000). The fair value for all long-term debt including current portions was estimated using discounted cash flows based on an estimate of the Utility's current borrowing rate for similar borrowing arrangements.

15. POST-EMPLOYMENT BENEFITS

Characteristics of benefit plans
The Utility sponsors a defined benefit pension plan for employees joining the Utility before January 1, 2002. The Utility also sponsors an executive defined benefit pension plan and supplemental executive retirement plan for a former executive. Benefits provided are calculated based on length of pensionable service, pensionable salary at retirement age and negotiated rates.

Employees joining the Utility after January 1, 2002 are not eligible to participate in the employee defined benefit pension plan. The Utility makes contributions to a Registered Retirement Savings Plan (“RRSP”) on behalf of these employees and employees hired before January 1, 2002 who belonged to the employee defined benefit plan and elected to opt out of that plan. The RRSP is a defined contribution retirement plan. The costs recognized for the period are equal to the Utility’s contribution to the plan. During 2021, these were $568,000 (2020 - $510,000).

The defined benefit pension plan for employees is regulated by the Office of the Superintendent of Financial Institutions ("OSFI") through the *Pension Benefits Standards Act* and regulations. This Act and accompanying regulations impose, among other things, minimum funding requirements. The executive defined benefit pension plan and supplemental executive retirement plan are not registered with OSFI and are not subject to minimum funding requirements of the Act.

15. POST-EMPLOYMENT BENEFITS - continued

These minimum funding requirements require the Utility make special payments as prescribed by the OSFI to repay any unfunded liability or solvency deficiency that may exist. For the employee defined benefit pension plan the Utility is currently required to pay $246,200 for 2022. This amount may change in future years and may be summarized as follows:

Start Date	Minimum Annual Payment	End Date
January 1, 2013	$24,900	December 31, 2027
January 1, 2014	$49,300	December 31, 2028
January 1, 2018	$61,000	December 31, 2032
January 1, 2019	$36,000	December 31, 2033
January 1, 2020	$75,000	December 31, 2034

A committee of the Utility's Board of Directors oversees these plans and is responsible for the investment policy with regard to the assets of these funds.

Risks associated with defined benefit plans
The defined benefit pension plans expose the Utility to risk such as investment risk and actuarial risk. Investment risk is the risk that the assets invested will be insufficient to meet expected benefits. Actuarial risk is the risk that benefits paid will be more than expected. There are no particular unusual, entity-specific or plan-specific risks or any significant concentration of risk.

Net defined benefit liability

	December 31 2021	December 31 2020
Present value of benefit obligations		
Balance, beginning of year	$ 31,318	$ 28,075
Employee contributions	48	45
Current service cost	468	409
Interest cost	785	872
Benefits paid	(814)	(772)
Actuarial (gains) on experience	(856)	(96)
Actuarial (gains) losses on financial assumptions	(2,168)	2,785
Balance, end of year	$ 28,781	$ 31,318
Fair value of plan assets		
Balance, beginning of year	22,247	20,386
Interest income on plan assets	554	628
Gains on plan assets	1,963	1,475
Employee contributions	48	45
Employer contributions	681	551
Benefits paid	(814)	(772)
Administrative costs	(68)	(66)
Balance, end of year	$ 24,611	$ 22,247
Effect of asset ceiling	82	-
Net defined benefit liability	$ 4,252	$ 9,071

15. POST-EMPLOYMENT BENEFITS - continued

Components of benefit plan cost:

	December 31 2021	December 31 2020
Current service cost	$ 468	$ 409
Interest cost	785	872
Interest income on plan assets	(554)	(628)
Administrative costs	68	66
Defined benefit expense in Statement of Operations	767	719
Defined contribution expense	568	510
Total benefit expense in Statement of Operations	$ 1,335	$ 1,229
Actuarial (gains) losses on obligation	(3,024)	2,689
Gains on plan assets	(1,963)	(1,475)
Effect of asset ceiling	82	-
Total re-measurements included in Other Comprehensive Income	$ (4,905)	$ 1,214
Total benefit costs recognized in Statement of Operations and Other Comprehensive Income	$ (3,570)	$ 2,443

Distribution of plan assets of defined benefit pension plans
The fair value of the defined benefit pension plans' assets are based on market values as reported by the defined benefit pension plans' custodians as at each applicable Statement of Financial Position date. The distribution of assets by major asset class is as follows:

	December 31, 2021	December 31, 2020
Equities	42.6%	51.9%
Fixed income securities	36.5%	39.0%
Real estate	20.9%	9.1%

Significant assumptions:

	December 31, 2021	December 31, 2020
Discount rate - accrued benefit obligation	3.00%	2.50%
Assumed rate of compensation increase	2.80%	2.80%
Pension growth	2.00%	2.00%

Sensitivity analysis of the defined benefit pension plans:
The sensitivities of each key assumption used in measuring accrued benefit obligations at each Statement of Financial Position date have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously. The sensitivity analysis has been determined based on reasonably possible changes of the respective assumptions occurring at the end of the reporting period. The mortality assumptions are based on the 2014 Canadian Pensioner Mortality Private Table projected with full generational mortality improvements using scale MI-2017.

15. POST-EMPLOYMENT BENEFITS - continued

Assumptions and sensitivity to the recognized post-employment benefits liability balance at December 31, 2021

Assumption	+1%	-1%	+1%	-1%
Discount rate	-13%	16%	$ (3,758)	$ 4,714
Salary growth	1%	-1%	156	(149)
Pension growth	15%	-12%	4,226	(3,472)
Life expectancy (1 year movement)	3%	-3%	830	(836)

Assumptions and sensitivity to the recognized post-employment benefits liability balance at December 31, 2020

Assumption	+1%	-1%	+1%	-1%
Discount rate	-14%	18%	$ (4,428)	$ 5,622
Salary growth	1%	-1%	231	(220)
Pension growth	16%	-13%	4,878	(3,449)
Life expectancy (1 year movement)	3%	-3%	940	(944)

The sensitivity analysis presented above may not be representative of the actual change in the defined benefit obligation as it is unlikely that the change in assumptions would occur in isolation of one another as some of the assumptions may be correlated.

Furthermore, in presenting the above sensitivity analysis, the present value of the defined benefit obligation has been calculated using the projected unit credit method at the end of the reporting period, which is the same that is applied in calculating the defined benefit obligation liability recognized in the Statement of Financial Position.

The Utility pays the balance of the cost of the employee benefit plan over the employee contributions, as determined by the actuary. Members are required to contribute 3.5% of earnings up to the Year's Maximum Pensionable Earnings ("YMPE") plus 5% of earnings above the YMPE. Permanent part-time members will have required contributions as above multiplied by their permanent part-time service ratio. Employees can make additional contributions to purchase ancillary benefits. Members choose the ancillary benefit on termination of service or on retirement.

The average duration of the benefit obligation is 14.9 years (2020 - 16.3 years). The Utility expects to make payments of $606,800 (2020 - $766,800) to the defined benefit plans during the next financial year.

December 31 2021

16. CONTRIBUTIONS IN AID OF CONSTRUCTION

	Government of Canada	Parent since 1998	Yukon Government since 1998	Pre-1998 contributions	Total
Cost:					
At January 1, 2020	$ 71,299	$ 89,730	$ 11,698	$ 1,739	$ 174,466
Additions	12,395	-	-	-	12,395
At December 31, 2020	$ 83,694	$ 89,730	$ 11,698	$ 1,739	$ 186,861
Additions	9,266	-	200	-	9,466
At December 31, 2021	$ 92,960	$ 89,730	$ 11,898	$ 1,739	$ 196,327
Accumulated amortization:					
At January 1, 2020	$ 8,002	$ 13,047	$ 2,491	$ 1,465	$ 25,005
Amortization	991	1,604	229	43	2,867
At December 31, 2020	$ 8,993	$ 14,651	$ 2,720	$ 1,508	$ 27,872
Amortization	1,204	1,604	228	44	3,080
At December 31, 2021	10,197	16,255	2,948	1,552	30,952
Net book value:					
At December 31, 2020	$ 74,701	$ 75,079	$ 8,978	$ 231	$ 158,989
At December 31, 2021	$ 82,763	$ 73,475	$ 8,950	$ 187	$ 165,375

17. DEFERRED REVENUE

	Customer Contributions	Decommissioning Fund	Total
At January 1, 2020	$ 17,886	$ 2,769	$ 20,655
Additions	1,071	30	1,101
Revenue recognized in Sales of Power (Note 18)	(1,612)	-	(1,612)
At December 31, 2020	$ 17,345	$ 2,799	$ 20,144
Additions	1,111	13	1,124
Revenue recognized in Sales of Power	(1,625)	-	(1,625)
At December 31, 2021	$ 16,831	$ 2,812	$ 19,643

Customer contributions represent monies paid or assets contributed by customers for connection to the grid. The contributions are recognized into revenue when the performance obligation is satisfied.

The decommissioning fund represents monies paid in advance by an industrial customer to decommission the spur line that connects its operation to the Utility's grid. Under a power purchase agreement, the customer has the financial responsibility for decommissioning activities to be performed by the Utility on its behalf. Any amounts not required for decommissioning will be refunded to the customer. This money accrues interest at the rate equal to the three month Canadian Dealer Offered Rate ("CDOR"). This amount will be recognized to revenue when uncertainty associated with its recognition is satisfied.

18. SALES OF POWER

	2021	2020
Wholesale	$ 46,502	$ 44,721
Industrial	19,438	13,832
General service	8,051	8,165
Residential	4,175	4,049
Secondary sales	330	8
Sentinel and street lights	137	132
	$ 78,633	$ 70,907

19. OTHER REVENUE

During 2020 penstock inspections, deformation was noticed in WH1 and WH2 penstocks and major repairs were required before the units could be put back into service. The repairs of WH1 were completed in 2020 but the repairs of WH2 continued in 2021. During the year, the Utility incurred $2,445,000 (2020 - $3,631,000) of costs due to repairs required at the penstocks (see Note 10(a)(v)) and recorded $2,368,000 (2020 - $3,531,000) of insurance proceeds in revenue. The Utility has recorded a receivable of $2,137,000 (2020 - $3,531,000).

20. OPERATIONS AND MAINTENANCE EXPENSES

	2021	2020
Fuel	$ 8,935	$ 15,217
Regulatory account expenses (Note 10 (c))	6,968	11,434
Wages and benefits	6,696	6,508
Contractors	4,929	3,943
Rent	2,971	2,138
Loss on asset disposals	1,803	-
Materials and consumables	1,284	1,847
Travel	340	314
Communication	92	79
	$ 34,018	$ 41,480

21. ADMINISTRATION EXPENSES

	2021	2020
Wages and benefits	$ 6,470	$ 5,935
Insurance and taxes	2,380	2,180
External labour	1,893	1,810
Materials, consumables and general	1,787	1,702
Licences and fees	922	722
Board fees	115	135
Travel	86	111
	$ 13,653	$ 12,595

22. RELATED PARTY TRANSACTIONS

The Utility is related in terms of common ownership to all YG departments, agencies and Territorial Corporations. Transactions are entered into in the normal course of operations with these entities. All sales of power transactions are recorded at the rates approved by the YUB.

Interim Electrical Rebate program revenues are received from YDC in accordance with terms established by YG which established the program to protect certain ratepayers. These revenues are included in sales of power on the Statement of Operations and Other Comprehensive Income.

The following table summarizes the Utility's related party transactions with YDC for the year:

	2021	2020
Revenue		
Sales of service	$ 4	$ 4
Rate subsidy	280	281
Operating expenses		
Interest expense	$ 4,005	$ 4,478
Other receipts/additions		
Long-term debt	-	3,959
Contributed surplus	-	1,368
Other payments/deductions		
Repayment of long-term debt	$ 4,860	$ 4,860
Construction financing	-	3,959
Construction financing	-	1,368

22. RELATED PARTY TRANSACTIONS - continued

At the end of the year, the amounts receivable from and due to related parties are as follows:

	December 31 2021	December 31 2020
YDC		
Accounts receivable	$ 925	$ 10,888
Accounts payable	1,216	1,049
Construction financing	21,017	21,017
Current portion of long-term debt	4,860	4,860
Long-term debt	120,761	125,620
YG		
Accounts receivable	$ 331	$ 90
Accounts payable	-	68

Included in Accounts receivable from YDC is an amount of $896,000 for capital projects funded by YG and the federal government (2020 - $10,458,000). These balances are non-interest bearing and payable on demand except for construction financing and long-term debt.

Transactions with Key Management Personnel
The Utility's key management personnel include members of the senior management team and the Board of Directors, a total of 17 individuals (2020 - 15 individuals). Key management personnel compensation is as follows:

Year ended December 31	2021	2020
Short-term employee benefits	$ 1,846	$ 1,634
Post-employment benefits	209	198
	$ 2,055	$ 1,832

23. COMMITMENTS

Aishihik water licence
The Yukon Water Board issued a water use licence in 2002, valid until December 31, 2019, for the Utility's Aishihik Lake facility. In addition to maintaining a minimum and maximum water level, this licence commits the Utility to meet a number of future requirements including annual fish monitoring programs. Due to outstanding issues with affected stakeholders, the Utility was unable to secure a long term renewal of the licence prior to expiry. During 2019, a two month extension was granted and then, in order to ensure continued generation from this plant, the Utility made application for a short term (three year) renewal to the existing licence. This application was approved and a renewed licence was granted by the YWB effective March 1, 2020. This short term licence includes additional monitoring and potential operational adjustments, the cost of which will be charged to the fiscal year in which they occur. The Utility continues to work with affected parties with the objective of a longer term licence agreement prior to the expiry of the extension.

Fish monitoring programs are also required under an authorization provided by the federal government Department of Fisheries and Oceans, which is valid until December 31, 2022.

23. COMMITMENTS - continued

Contractual obligations
The Utility has entered into contracts to purchase products or services for which the liability has not been incurred as at December 31, 2021 as the product or service had not been provided. The total commitments at year end are $19,901,000 (2020 - $30,331,000).

24. CONTINGENCIES

Aishihik Third Turbine Project
This project was commissioned into service in December 2011. On March 2, 2012, the general contractor filed a claim with the Supreme Court of Yukon for $4,000,000 plus interest and costs alleging the Utility has not paid for work performed. During 2017, the Yukon Supreme Court issued an award in favor of the contractor. The Utility successfully appealed the award in 2018. A re-trial was held in April 2020; the decision of the judge was received on February 1, 2021. The trial resulted in a net award in favour of the Utility. During 2021 the Utility received a payment of $487,000. The Utility's claims for cost and interest are still to be adjudicated.

Asset Retirement Obligations
The Utility has not recognized a provision for the closure and restoration obligations for certain generation, transmission and distribution assets which the Utility anticipates maintaining and operating for an indefinite period, making the date of retirement of these assets indeterminate. These significant uncertainties around the timing of any potential future cash outflows are such that a reliable estimate of the liability is not possible at this time. A provision will be recognized when the timing of the retirement of these assets can be reasonably estimated.

25. PROVISION FOR ENVIRONMENTAL LIABILITIES

The Utility's activities are subject to various federal and territorial laws and regulations governing the protection of the environment or to minimize any adverse impact thereon. The Utility conducts its operations so as to protect public health and the environment and believes its operations are materially in compliance with all applicable laws and regulations.

The Utility has conducted environmental site assessments at all its diesel plant sites. No new environmental contamination was found. As at December 31, 2021 no new provisions for environmental liabilities, for which a legal obligation exists to remediate, have been identified by the Utility. The Utility has its Environmental Management System to monitor and assess previous and potential existing environmental liabilities on an ongoing basis. The Utility does not have a provision for environmental liabilities as there is no present obligation to remediate.

26. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

At December 31, 2021, the Utility's financial instruments included accounts receivable, bank indebtedess, accounts payable and accrued liabilities, construction financing, long-term debt and interest rate swaps. The fair values of accounts receivable, bank indebtedness, accounts payable and accrued liabilities and construction financing approximate their carrying values due to the immediate or short-term maturity of these financial instruments.
Interest rate swaps are financial contracts that derive their value from changes in an underlying variable. The fair value of the interest rate swaps is estimated using standard market valuation techniques and is provided to the Utility by the financial institution that is the counterparty to the transactions.

Interest rate risk
Interest rate risk is the risk that future cash flows or fair value of a financial instrument will fluctuate due to changes in market interest rates. The Utility's future cash flows are not exposed to significant interest rate risk due to its long-term debt having fixed interest rates, with the exception of the Bankers' Acceptances from the TD Bank. The Bankers' Acceptances have had the variable rate converted to a fixed rate using an interest rate swap to eliminate the interest rate risk.

As at December 31, 2021, the Utility had five (2020 - four) interest rate swap agreements in place. The three agreements from 2019 were amended on September 11, 2020 (see Note 14). The first agreement has a notional principal amount of $7.8 million (2020 - $8.2 million) and the agreement effectively changes the Utility’s interest rate exposure on this notional amount from a floating rate to a fixed rate of 2.06%. The second agreement has a notional principal amount of $21.5 million (2020 - $22.2 million) and the agreement effectively changes the Utility's interest rate exposure on the notional amount from a floating rate to a fixed rate of 3.40%. The third agreement has a notional principal amount of $6.3 million (2020 - $6.5 million) and the agreement effectively changes the Utility's interest rate exposure on the notional amount from a floating rate to a fixed rate of 2.64%. The fourth agreement has a notional principal amount of $4.6 million (2020 - $4.8 million) and the agreement effectively changes the Utility's interest rate exposure on the notional amount from a floating rate to a fixed rate of 2.06%. The fifth agreement has a notional principal amount of $7.5 million (2020 - $0) and the agreement effectively changes the Utility's interest rate exposure on the notional amount from a floating rate to a fixed rate of 2.88%.

The fair value of the interest rate swap agreements on December 31, 2021 was a liability of $2,479,000 (2020 -$5,050,000). The increase in the fair value in 2021 of $2,571,000 (2020 – decrease of $3,120,000) is recognized on the Statement of Operations and Other Comprehensive Income as an unrealized gain (loss). A 100 basis point increase or decrease in the interest rate assumption would have resulted in an increase/decrease in the interest rate swap agreements fair value of $5,020,000 (2020 - $4,710,000).

26. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS - continued

Interest rate risk - continued

The Utility has access to a $10 million line of credit. Effective June 6, 2019, the line of credit was increased temporarily to $26.5 million. Effective May 31, 2020, the line of credit was increased temporarily to $36.0 million. Effective April 22, 2021, the line of credit was increased temporarily to $43.0 million. The temporary increase expires June 30, 2022. The account accrues interest on withdrawals at prime rate minus 0.75% (2020 - 0.75%) per annum. Due to the short-term nature of the amount drawn on the line of credit and the Utility's cash balances with the same financial institution (Note 11), the interest rate risk is minimal.

Credit risk

Credit risk is the risk of failure of a debtor or counterparty to honour its contractual obligations resulting in financial loss to the Utility.

The following table illustrates the maximum credit exposure to the Utility if all counterparties defaulted:

	December 31 2021	December 31 2020
Accounts receivable	$ 16,123	$ 25,589
	$ 16,123	$ 25,589

Credit risk on accounts receivable is considered minimal as the Utility has experienced insignificant bad debt in prior years. In addition, its primary customer is a rate regulated utility that purchases power from the Utility for resale and as such these receivables are considered fully collectible. Included in the accounts receivable past due but not impaired at December 31, 2021 are $1,517,000 (2020 - $7,837,000) which management believes will be received in full.

Liquidity risk

Liquidity risk is the risk that the Utility will not be able to meet its financial obligations as they fall due. The Utility manages liquidity risk through regular monitoring of cash and currency requirements by preparing cash flow forecasts to identify financing requirements. The Utility's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Utility's reputation.

26. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS - continued

Liquidity risk - continued
The Utility's largest current liability is current portion of long-term debt which is predominantly due to the Parent. In addition, rate regulation assists the Utility with liquidity management by providing consistent revenues and a consistent debt to equity ratio.

Fair values
The following table illustrates the fair value hierarchy of the Utility's financial instruments as at December 31, 2021:

	Quoted prices in active markets (Level 1)	Other observable inputs (Level 2)	Unobservable inputs (Level 3)	Total
Derivative related liability	-	$2,479	-	$2,479
Long-term debt	-	-	$179,300	$179,300

The following table illustrates the fair value hierarchy of the Utility's financial instruments as at December 31, 2020:

	Quoted prices in active markets (Level 1)	Other observable inputs (Level 2)	Unobservable inputs (Level 3)	Total
Derivative related liability	-	$5,050	-	$5,050
Long-term debt	-	-	$186,600	$186,600

27. CAPITAL MANAGEMENT

The Utility's capital is its shareholder's equity which is comprised of share capital, contributed surplus and retained earnings. The Utility manages its equity by managing revenues, expenses, assets and liabilities to ensure the Utility effectively achieves its objectives while remaining a going concern.

The Utility has a policy which defines its capital structure at a ratio of 60% debt and 40% equity. This policy has been reviewed and accepted by the YUB.

The Utility monitors its capital on the basis of the ratio of total debt to total capitalization. Debt is calculated as total borrowings, which is comprised of long-term debt, including the portion of long-term debt due within one year, as well as the decommissioning fund (Note 17). Short-term debt related to assets under construction at the Statement of Financial Position date is excluded from the calculation of total debt, as the assets are similarly excluded from the determination of rate base. Total capitalization is calculated as total debt plus total shareholder's equity as shown on the Statement of Financial Position. The Utility maintains a balance in retained earnings as an indicator of the Utility's equity position.

27. CAPITAL MANAGEMENT - continued

The table below summarizes the Utility's total debt to total capitalization position:

	December 31 2021	December 31 2020
Long-term debt due within one year	$ 6,537	$ 6,280
Long-term debt	167,037	166,056
Total debt	173,574	172,336
Add decommissioning fund (Note 17)	2,812	2,799
Total debt to include in the calculation	$ 176,386	$ 175,135
Share capital	$ 39,000	$ 39,000
Contributed surplus	15,968	15,968
Retained earnings	82,684	64,249
Total shareholder's equity	137,652	119,217
Total capitalization	$ 314,038	$ 294,352
Total debt to total capitalization	56 %	59 %

There were no changes in the Utility's approach to capital management during the period.

28. SUBSEQUENT EVENTS

In January 2022, the Utility executed an Electricity Purchase Agreement ("EPA") with Tlingit Homeland Energy LP ("the Seller"). The agreement commits the Utility to the purchase of all electricity generated from a hydrogeneration facility to be constructed in Atlin, BC ("the Plant"), for an initial 40-year period. The Seller will build, own and operate the Plant and related transmission assets. The Plant is expected to be complete and operational in 2024. The EPA is subject to a number of conditions precedent including, among others, a review by the YUB, ongoing consultation with First Nations in the project area, approvals from the Taku River Tlingit First Nation Government and Yukon Government, and all government grant funding and project permits being obtained by the Seller. An estimate of the financial impact of the EPA on the Utility's future results of operations and financial position cannot be made at this time.

Environmental Benefits Statement

This report is printed on 100 percent postconsumer waste material. It is Forest Stewardship Council TM Canada certified, processed chlorine free, alkaline pH, and meets the credibility of Canadian Standards Association (CSA) for longevity.

By using this paper, Yukon Energy saved the following resources based on a copy run of 50 reports:

Wood Use: 450 kg

Water: 1,850 L

Energy: 300 kWhr

Solid Waste: 25 kg

Greenhouse Gases: 62.50 kg CO_2 equiv.

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