Yukon Energy Corporation

2017/2018 General Rate Application

Summary and Overview of Application
August 3, 2017

YUKON ENERGY

Outline of Presentation

- Introduction
- Requested Orders
- Company Background
- Context for this GRA
- Drivers for GRA
- Other Matters

Introduction: Application

- ✓ Filed with YUB on June 22, 2017
- ✓ Two test years – 2017 and 2018
- ✓ Approvals sought:
  - o 2017 & 2018 revenue requirement;
  - o Recovery of revenue shortfall applicable;
  - o Revised Rider F – Fuel Rider;
  - o Revised Diesel Contingency Fund (DCF) Term sheet; and
  - o Interim refundable rate rider
- ✓ Other Matters (out of scope or no approvals being sought):
  - o Cost of Service & Rate Design;
  - o Resource Plan; and
  - o Rate Schedule 42 Energy Reconciliation Adjustment (ERA) – under appeal & not addressed in this Application

Introduction: YUB Mandate and Guidance

- ✓ YUB authority under the Public Utilities Act (PUA) to make orders regarding rates and terms of service;
- ✓ Order in Council (OIC) rate policy directives under PUA for YEC & AEY rates:
  - OIC 1995/90 -Rate Policy Directive
    - Retail rate equalization, major industrial rates, wholesale rates, fuel adjustment riders, & other matters
  - Modifications to OIC 1995/90:
    - OIC 2007/94 (Major Industrial Customer Directive)
    - OIC 2008/149(Retail Rate Adjustment Directive)
    - OIC 2012/68 (Retail & Industrial Rate Adjustment Directive)
    - OIC 2014/23 (Retail & Industrial Rate Adjustment Directive)

Introduction: YUB Process

Order 2017-04 established the following hearing process & timeline

Action	Date (2017)
Register with Board	July 21
YEC Workshop	August 3
Information Requests to YEC	August 25
YEC Response to Information Requests	September 22
Intervenor Evidence	October 5
Information Requests to Intervenors	October 19
Information Responses from Intervenors	November 2
YEC Rebuttal Evidence (if necessary)	November 9
Oral Hearing - Coast High Country Inn	November 28-30
Final Argument	December 7
Reply Argument	December 21

Introduction: Outline of Supporting Documents

The Application Volume 1 includes the following supporting information:

- ✓ Tab 1: Introduction
- ✓ Tab 2: Yukon Energy System Sales & Generation
- ✓ Tab 3: Revenue Requirements
- ✓ Tab 4: Rates
- ✓ Tab 5: Capital Projects
- ✓ Tab 6: Board Directives
- ✓ Tab 7: Financial Schedules
- ✓ Tab 8: Return on Equity
- ✓ Tab 9: 2015 Audited Financial Statements
- ✓ Tab 10: Orders in Council

Volume 2 - YEC 2016 Resource Plan

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Requested Orders
Revenue Requirement

1. **Approval of forecast Revenue Requirement**
   2017 - $48.544 million
   2018 - $49.864 million

- **Fuel and Purchased Power Costs**
  - Adjusted Fuel Prices - $0.2633/kW.h – diesel; $0.1467/kW.h - LNG
  - LNG/Diesel Generation – 90% LNG; 10% diesel
  - Update to Rider F & Diesel Contingency Fund –LNG impacts
- **Non-Fuel Operating and Maintenance**
  - Reserve for Injuries & Damages (RFID) **–** update for current history
  - Vegetation Management Deferral Account – retire for new policy

Requested Orders
Revenue Requirement (cont'd)

1. **Approval of forecast Revenue Requirement**
   2017 - $48.544 million
   2018 - $49.864 million

- **Depreciation & Amortization**
  - Planning Cost Accounting Policy - Appendix 5.1
  - DSM Accounting Policy – Appendix 5.2
  - Hearing Cost Reserve Account – update for current context
- **Mid-Year 2017 and 2018 Forecast Rate Base**
  - Major Capital Projects (over $1 million) - $60.4 million
  - Other Property Plant & Equipment Capital Projects – approx. $17.0 million
  - Deferred Costs for feasibility, supply planning, regulatory, relicensing and dam safety at approx. $15 million
- **Return on Rate Base**
  - $13.288 million in 2017 and $14.348 million in 2018

Requested Orders
Rate Adjustments

2. Approval of 2017 and 2018 rate adjustments

- o 2017/2018 Retail and Industrial Rates – Rider J Provisions
  - > 9.04 percentage point increase in current YEC Rider J, effective January 1, 2017
  - > 2.07 percentage point further increase to Rider J%, effective January 1, 2018

- o Interim Refundable Rate Increase by Sept. 1, 2017 (Rider J)
  - > Implement 2017 Rider J rate increase to current Rider J, effective Sept. 1, 2017;
    - – Interim refundable rate rider – 9.04 percentage point increase in Rider J.
    - – Less than 1/3 of forecast 2017 revenue shortfall will be collected by interim Rider J over 2017.

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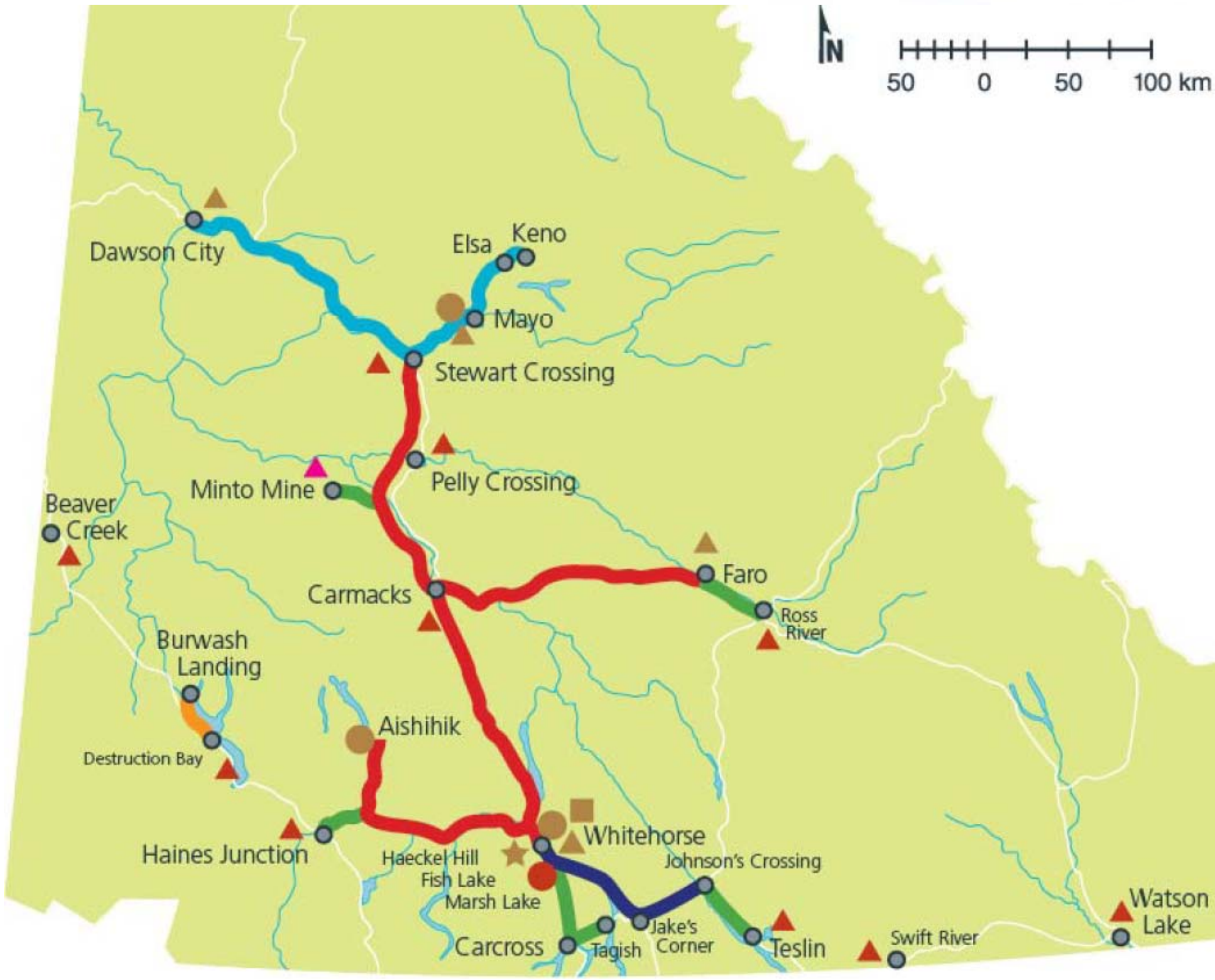
Company Background

- ✓ Yukon Energy is the main generator and transmitter of electrical energy in the Yukon:
  - o 90% of annual Yukon power generation;
  - o Total Grid Generating Capacity
    - > 92 MW hydro
    - > 39 MW thermal
  - o 1,100 km of transmission
- ✓ Wholesales – approx. 80% of sales
- ✓ Retail service - Dawson City, Mayo and Faro.
- ✓ Industrial – Capstone's Minto Mine
- ✓ Secondary sales – Surplus hydro (renewed sales)

Company Background
Yukon's Transmission and Generation Facilities



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Context for this GRA
Return on Equity (ROE) since 2013

Return on Equity Earned by Yukon Energy

Year	ROE without new GRA[1]	ROE after Other Factors
2013 GRA	8.25% GRA Compliance	
2013 Actual	7.42%	
2014 Actual	8.44%	
2015 Actual	8.10%	6.45% ex. debt refinance[2]
2016 Actual	8.69%	7.18% ex. debt refinance[2]
2017 Forecast	8.17% at existing rates	3.96% after GRA impacts[3]
2018 Forecast	7.89% at existing rates	3.18% after GRA impacts[3]

Notes: 1. Actual or projected ROE absent a new GRA.

2. ROE in 2015 & 2016 without debt refinancing by YDC.

3. Added rate base & other adjustments resulting from the new GRA, but absent rate changes.

Context for this GRA

Mitigation Measures employed to Defer/ Reduce Rate Increases

Debt Re-Negotiation with YDC

- Interest cost reductions of $1.5 million in 2017 and $1.4 million in 2018

Mayo Flexible Debt Financing

- Lower interest reflecting lower loads since 2013

YDC Contributions for capital projects & planning costs

- In 2015, YDC made a $22.4 million capital contribution to Yukon Energy
- $18.3 million offset capital costs of LNG Project & $4.2 million offset amounts for deferred projects

Secondary Sales Revenues

- Decline in load resulted in opportunities for sec. sales & added revenues between 2013 and 2016 ranging from $0.275 million to $0.544 million; and $0.642 million forecast each test year

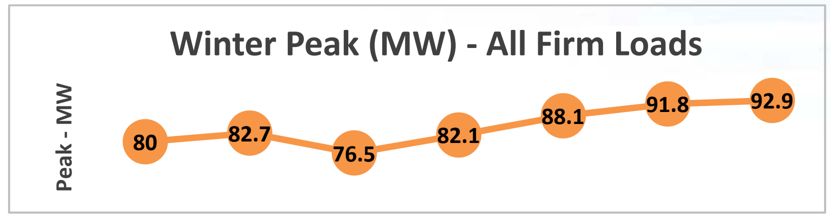
Adjusted Thermal Fuel Costs

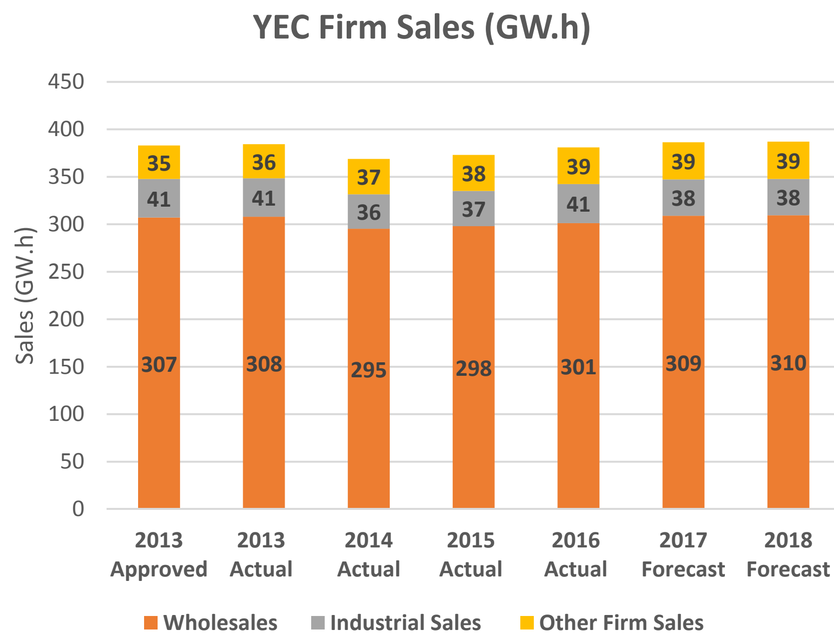
- Reduction in thermal generation costs with lower loads (DCF reactivation impacts)
- Reduction in YEC fuel costs with LNG generation

Context for this GRA
Changing Load Profile – Summary

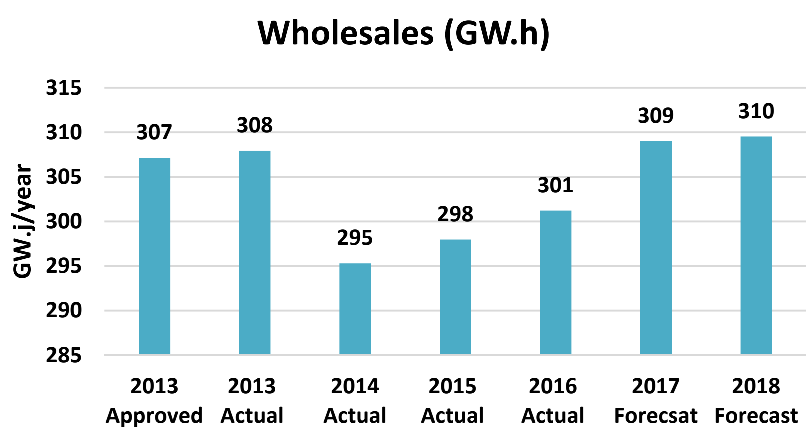
- ✓ Increased peak winter loads
  - o 80 MW - 2013 approved
  - o 88.1 MW - 2016 actual
  - o 92.9 MW – 2018 forecast

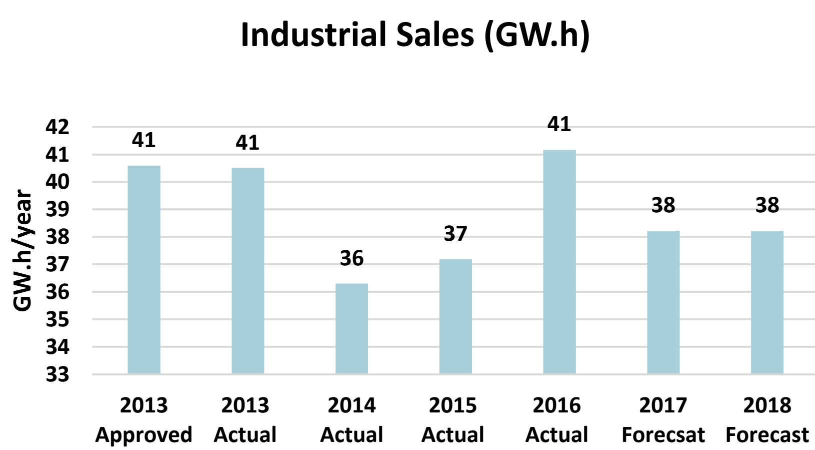
- ✓ Flat annual firm sales
  - o 383 GW.h - 2013 approved
  - o 381 GW.h - 2016 actual
  - o 387 GW.h - 2018 forecast

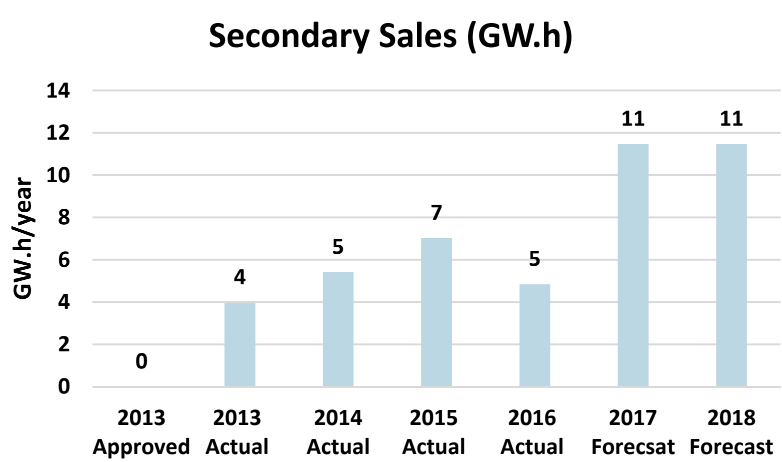




Context for this GRA
Changing Load Profile - Energy Sales by Class







Context for this GRA

Changing Load Profile - Dependable Capacity Shortfall

- ✓ Increased winter peaks 2013-2016
  - > Total Peak up 8 MW
  - > Non-industrial peak up 10 MW
- ✓ Dependable Capacity not growing;
  - > Estimated for Single Contingency (N-1) Event
  - > 77.5 MW dependable capacity for 2013 GRA
  - > Since 2013, retired 2 Mirrlees and installed 2 new natural gas units
  - > 76.7 MW dependable capacity for 2017-18 test years
- ✓ Dependable Capacity shortfalls result
  - > 6.5 MW Dependable Capacity surplus in 2013 GRA
  - > 7.6 to 8.7 Dependable Capacity shortfall in 2017-18 test years

Context for this GRA

Changing Load Profile – Impacts Going Forward

- ✓ Industrial mine loads continue to be a major uncertainty
    - > Need planning flexibility
- ✓ Without new resources, N-1 capacity shortfall grows
    - > 10-11 MW by 2019
    - > 23-24 MW by 2021 (assume 8.5 MW of Mirrlees units retired)
- ✓ The 2016 Resource Plan Update recommended resource options which will affect rate base after 2018.
    - o Proposed new capacity resources for in-service after 2018 include:
        - > LNG Third Engine (4.4 MW in-service in Q1-2019),
        - > Battery (4 to 8 MW options, in-service planned later in 2019),
        - > Thermal Project (20 MW in-service in late 2020).
    - o Proposed hydro plant uprates, refurbishments & storage enhancement projects will also affect rate base after 2018.

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Drivers for GRA

Rate Revenue Shortfall for 2017 and 2018 & 9.08% Rate Increase

Yukon Energy's forecast rate revenue requirement shortfall ($000s) of $5,348 in 2017 and $6,585 in 2018 is described in the table below.

The 2018 revenue shortfall requires a 9.08% rate increase for total YEC & AEY consolidated retail and industrial revenues of $72.5 million at existing rates.

Yukon Energy Rate Revenue Shortfall ($000)	**2017**	**2018**
Revenue Requirement	$48,544	$49,864
Less: Other Revenues	$ 253	$ 253
Less: Secondary Sales	$ 642	$ 642
Revenue Required from Firm Rates	$47,649	$48,969
Less: Revenues from Firm Sales at Existing Rates [includes Rider J]	$ 42,301	$42,384
Additional Firm Rate Revenues Required	**$5,348**	**$6,585**
Total Consolidated YEC-AEY Revenues at Existing Rates	72,429	72,532
Average YEC Rate Increase Required	**7.38%**	**9.08%**

Drivers for GRA

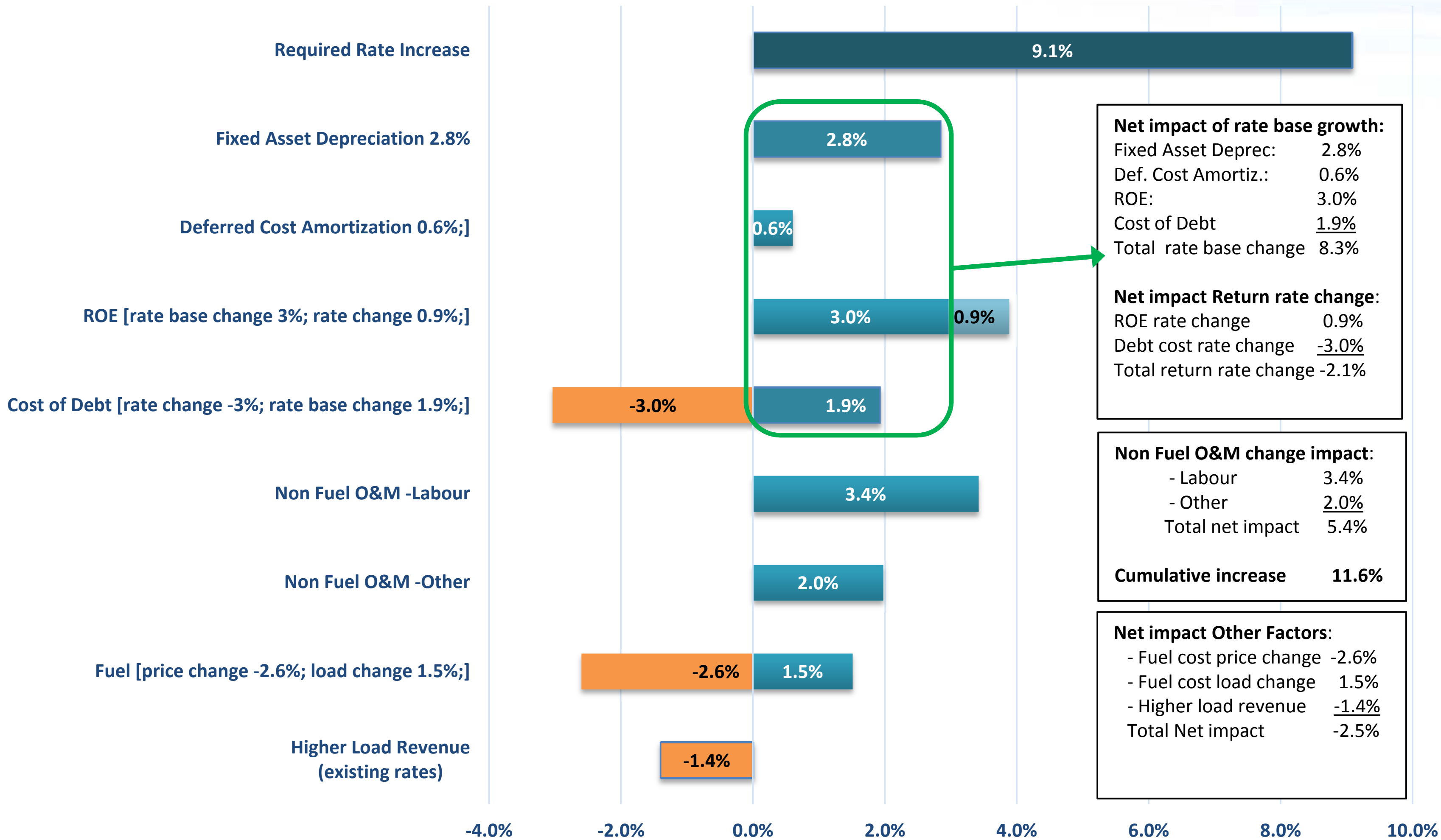
Revenue Requirement Change – 2018 Forecast vs 2013 Approved

The table below shows the change in revenue requirement by component in 2018 compared to 2013 Approved Costs, & each component's share of the 2018 Revenue Shortfall of $6.585 million

	Change ($ Million)	% increase or decrease	Share of 2018 Revenue Shortfall
Fuel & Purchased Power	(793)	(24.8%)	(12.0%)
Non-fuel O&M	3.905	21.6%	59.3%
Depreciation & Amortization	2.490	28.9%	37.8%
Return on Rate Base	2.000	16.2%	30.4%
Total Revenue Requirement	**7.601**	**18.0%**	**115.4%**
Revenue at Existing Rates	1.016	1.4%	-15.4%
Revenue Shortfall (2018)	**6.585**	**9.1%**	**100.0%**

Drivers for GRA

Factors Affecting 9.1% Rate Increase



Net impact of rate base growth:

Fixed Asset Deprec:	2.8%
Def. Cost Amortiz.:	0.6%
ROE:	3.0%
Cost of Debt	1.9%
Total rate base change	8.3%

Net impact Return rate change:

ROE rate change	0.9%
Debt cost rate change	-3.0%
Total return rate change	-2.1%

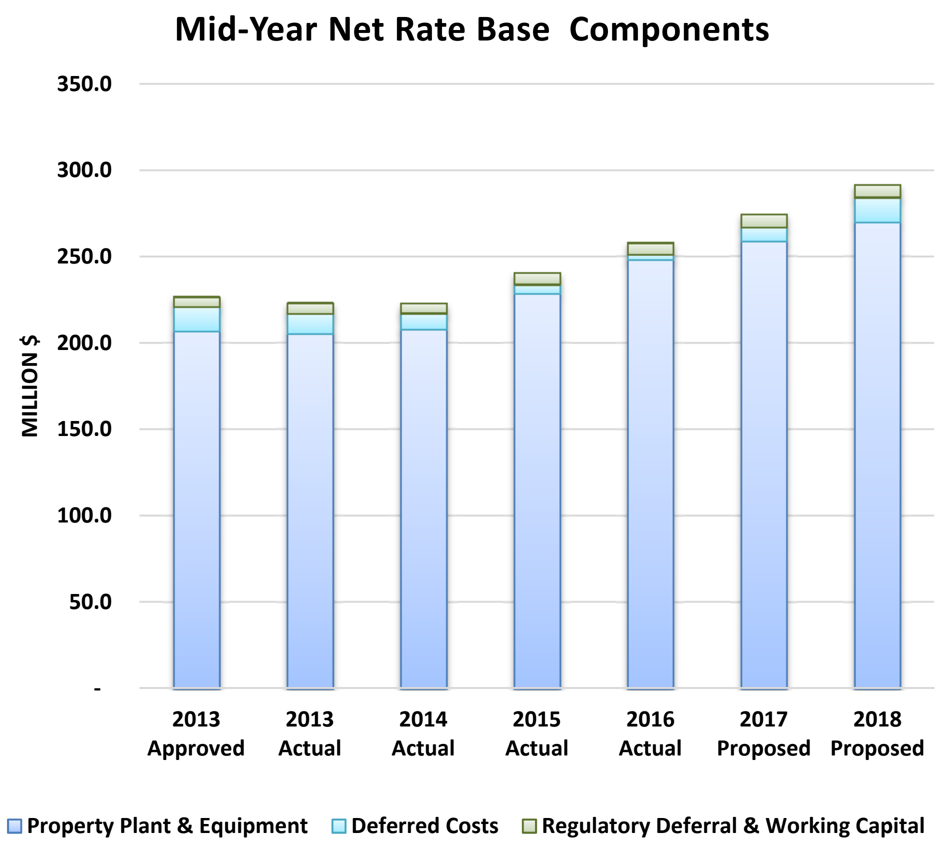
Non Fuel O&M change impact:

- Labour	3.4%
- Other	2.0%
Total net impact	5.4%
Cumulative increase	**11.6%**

Net impact Other Factors:

- Fuel cost price change	-2.6%
- Fuel cost load change	1.5%
- Higher load revenue	-1.4%
Total Net impact	-2.5%

Drivers for GRA
Rate Base Growth – Impacts on Rates



- **Net Rate Base increase (mid-year):** +$64.9 million (+28.6%)
- **Depreciation & Amortization expense growth:** +$2.5 million/year (+28.9%)
- **Return on Rate Base (debt and equity) growth:** +$3.5 million/year (+28.6%) excludes changes in debt interest costs or approved equity return %

Drivers for GRA

Rate Base Growth – Property, Plant & Equipment

- ✓ 2017/18 GRA rate base changes: 2 major capacity projects ($35.0 million net) and 8 major sustaining capital projects ($25.4 million):

Capital Project Spending – Capacity	Total ($35 M)	Completed
LNG Plant (net of $18.3 million contribution)	$23.6	2015
Whistle Bend Supply/ Takhini Upgrade	$11.4	2015

Capital Project Spending – Sustaining Capital	Total ($25 M)	Completed
Aishihik Elevator Shaft Structural Steel Rehab.	$10.12	2017
Aishihik Electrical & Control Upgrades	$2.51	2018
Communications Upgrades	$1.00	2018
Hydro Unit #WH4 Overhaul	$4.29	2017
Hydro Unit #2 MH2 Overhaul	$1.66	2018
T&D Breaker Replacements	$1.35	2018
T&D Line Replacement	$1.75	2018
Wareham Spillway Gate Hoist Replacements	$2.70	2015

Drivers for GRA
Rate Base Growth – Major Deferred Cost & Other WIP Projects

- ✓ Other 2017/18 GRA rate base changes from key projects:
  - o 3 major deferred cost projects ($9.8 million) for future generation and transmission requirements – see below
  - o $8.3 million added to rate base in 2017 and 2018 from other deferred projects
  - o Other 2017 WIP transfers include $6.3 million for deferred overhauls and about $6.5 million of other deferred costs

Deferred Project Spending –Future Generation & Transmission	Total ($9.8M)	Completed
Demand Side Management (work through 2018)	$3.32	2018
Resource Plan Update (2016)	$2.00	2017
Gladstone Diversion Project (closed feasibility study)	$4.52	2017

Other Matters

Rate Base Growth – GRA not affected by Deferred Costs Remaining in WIP and Post 2018 Projects

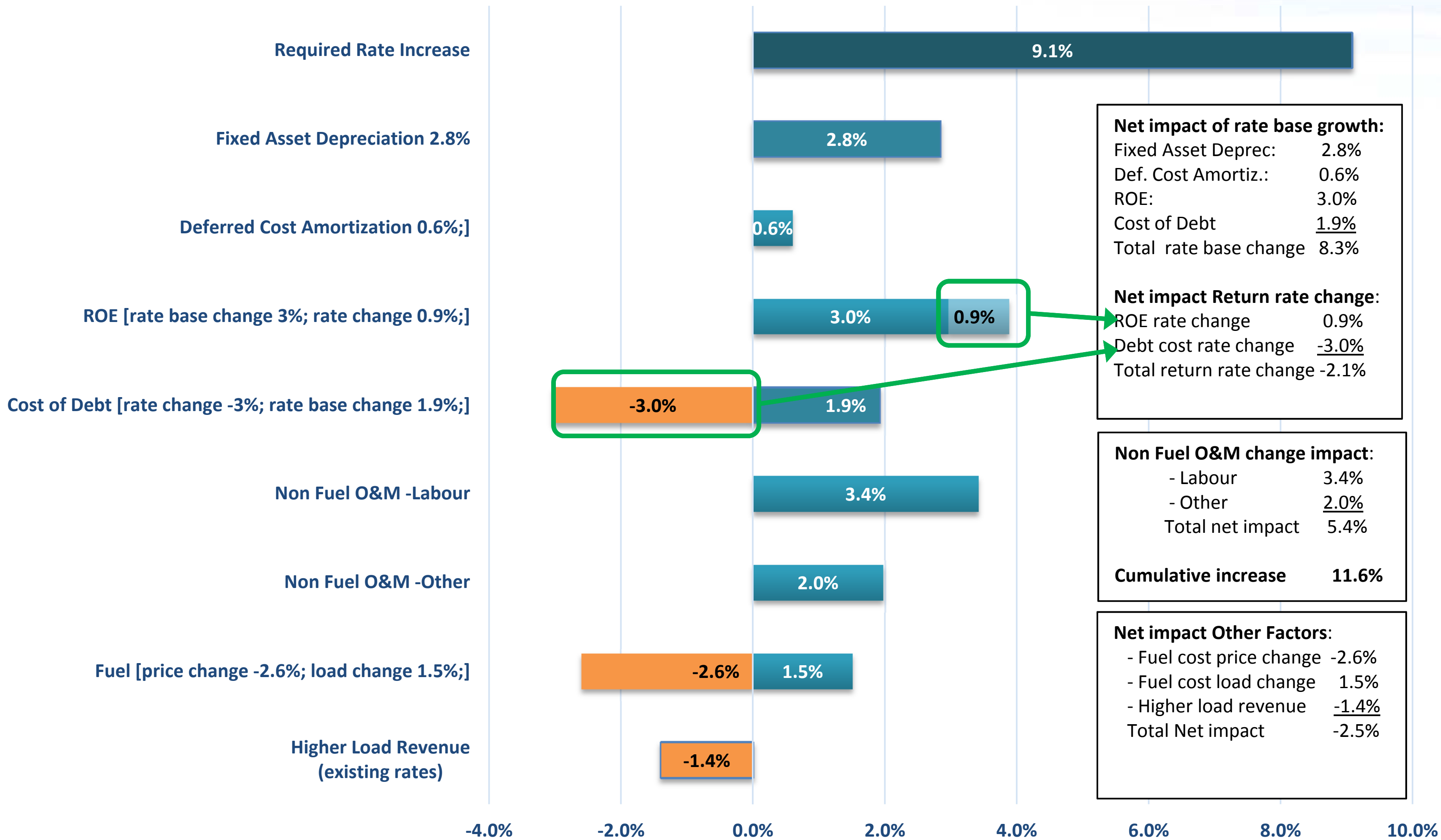
- ✓ Over $35 million in WIP at end of 2018 for 10 major projects projected to come into service potentially in 2019-2024 period at final costs exceeding $235 million

Deferred Cost Major Projects (WIP 2018)	2018 WIP ($million)	Est. Cost ($million)	Projected In-Service
Capacity Requirements			
LNG Third Engine	6.0	6.2	2019
Battery Project	8.9	21.7-27.4	2020
Thermal Plant Project	4.2	62.3	2021
Other Future Generation & Transmission			
Marsh Lake Storage Enhancement (SLESP)	8.2	11	2020*
Mayo Lake Storage Enhancement (MLESP)	3.4	20	2022*
Small Hydro	0.6	103	2023-24*
Sustaining Capital			
Aishihik Relicensing	2.9	3.6	2019
Whitehorse Uprate	0.4	25.0	2020
Aishihik Uprate	0.4	4.7	2021*
Mayo Lake Outlet Channel	0.4	See MLESP	2022*
Mayo Refurbishment	-	27	2022
Total Deferred Major Projects	**35.2**	**262.8**	

* Conditional on sufficient new mine connection

Drivers for GRA

Factors Affecting 9.1% Rate Increase

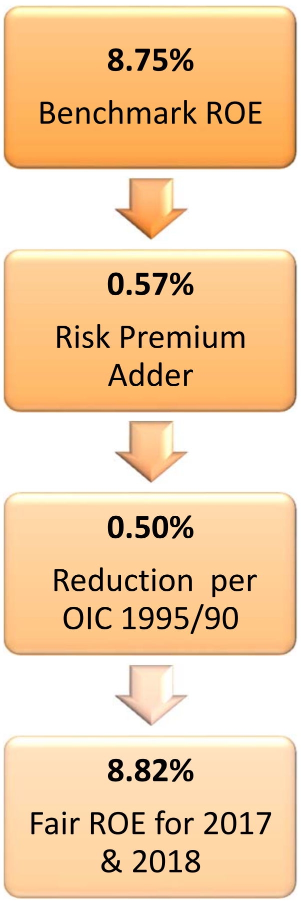


Drivers for GRA
Lower Return Rate Costs

✓ Lower average return on rate base for 2018 compared with 2013 approved reflects interest cost savings that offset higher ROE return %

	2013 Approved	2018 Proposed
Long-term Debt Interest	3.58%	2.32%
Return on Equity	8.25%	8.82%
Average Return on Rate Base	**5.45%**	**4.92%**

Drivers for GRA
Return on Equity



- ✓ Fair ROE based on BCUC benchmark & past Yukon precedents
  - o Propose to use BCUC 8.75% benchmark & apply a 0.57% risk premium; with deduction of 0.50% as directed by OIC this results in Fair ROE of 8.82%.
- ✓ Use simplified approach previously approved in 2005 (Order 2015-12) and 2008/09 (Order 2009-8)
  - o In 2005, a risk premium of 0.52% was approved based on the midpoint of the range of risk premium adders used for BCUC-regulated utilities considered potentially comparable with YEC [40% for FortisBC Energy; 65% for PNG-West]
  - o Today, a risk premium adder of 0.57% is proposed [mid-point of FortisBC Energy at 40% and PNG-West at 75%].

Drivers for GRA

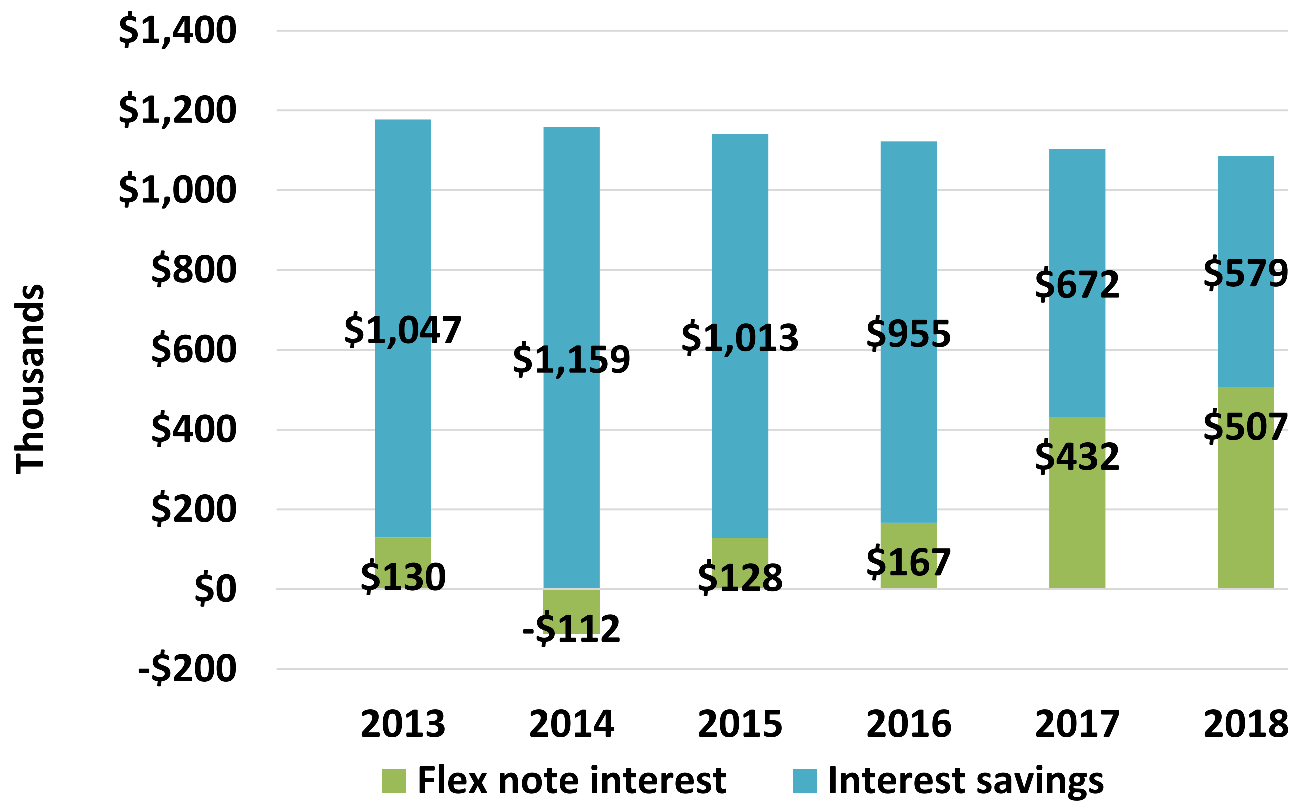
Lower Cost of Debt

- ✓ Average debt cost in 2018 forecast at 2.32%
  - o Decrease of 1.26% from 2013 approved average of 3.58%
- ✓ Factors that have helped reduce the average cost of debt include:
  - o **2015 Refinancing of YDC Debt**
    - > YDC Refinanced Term Note – refinancing reduced interest payments
      - – Reduction in 2017 of $1.5 million
      - – In 2018 - $1.4 million
  - o **Mayo B Flexible Debt Provisions**
    - > Max. face interest rate of 5.46%;
    - > forgives interest expense if Integrated Grid load is lower than Min. Grid Load indicated in note
    - > Ensure Mayo B net generation costs not exceed 11 c/kWh ($2012)
    - > Reduces interest by $0.579 million in 2018

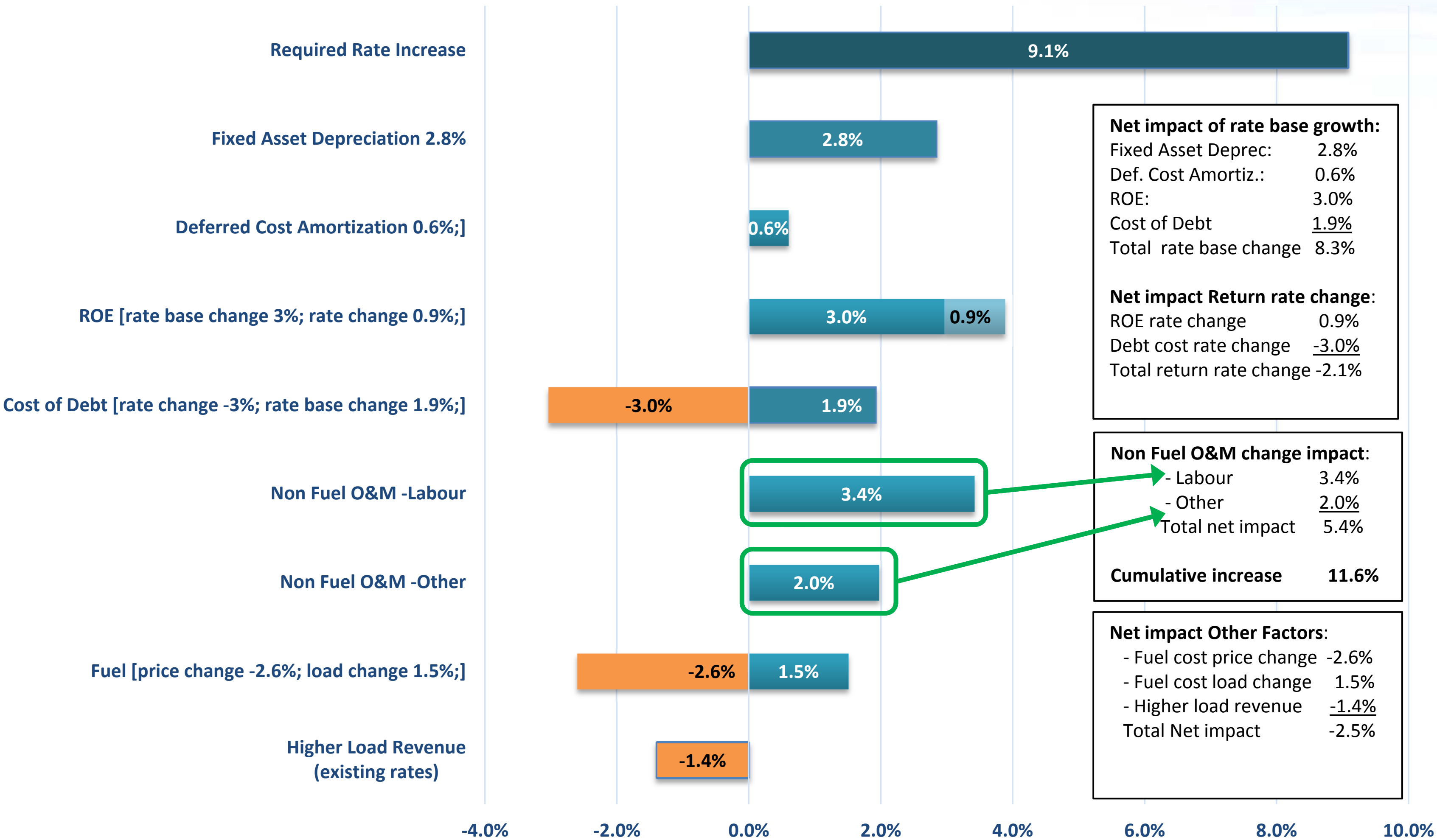
Drivers for GRA

Lower Cost of Debt – Impact of Mayo B Flexible Debt

- ✓ Mayo B Flexible Debt Note reductions in annual interest cost ($000)

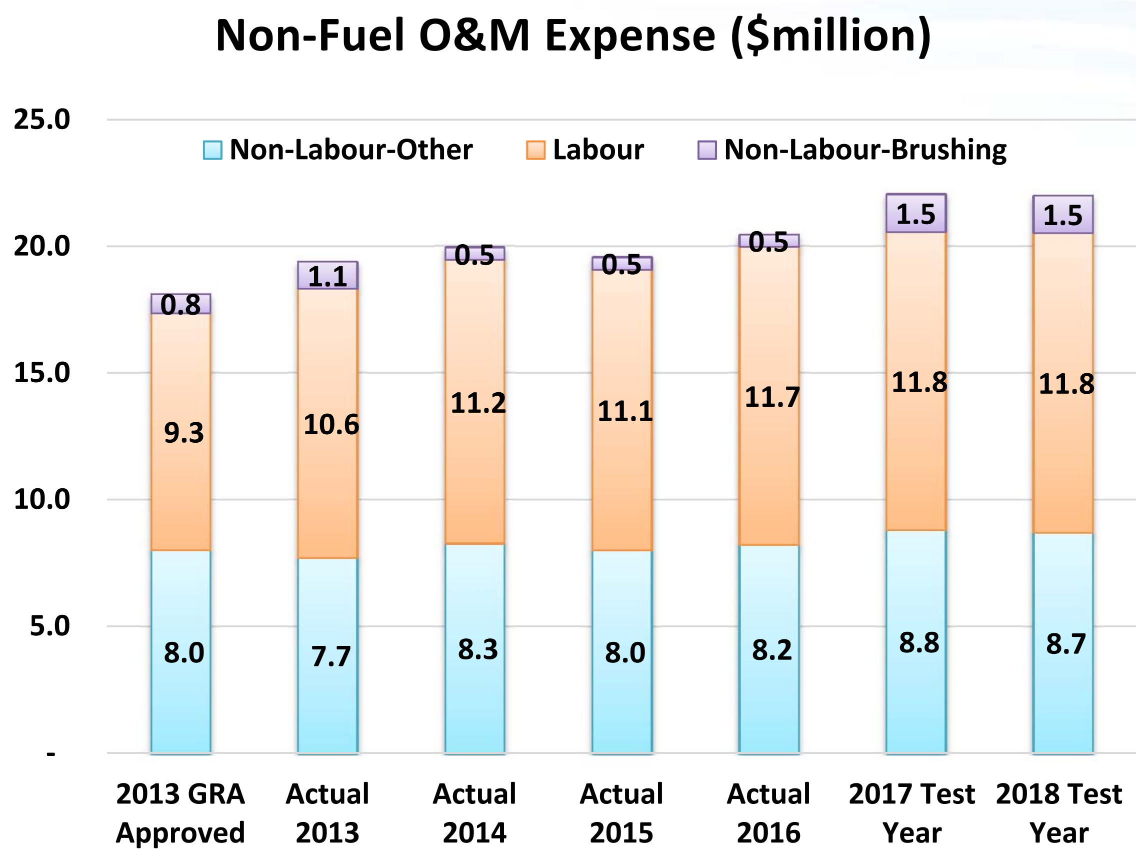


Drivers for GRA
Factors Affecting 9.1% Rate Increase



Drivers for GRA
Non-Fuel O&M Expense Growth

- ✓ Starting in 2013, higher actual non-fuel O&M expense than 2013 approved in each year
- ✓ 2018 Test Year non-fuel O&M is forecast to be $3.9 million (22%) higher than 2013 approved.
  - o $2.5 million increase in labour expense
  - o $1.4 million increase in non-labour non-fuel expense
    - > 50% of the non-labour increase is for brushing ($0.7 million)



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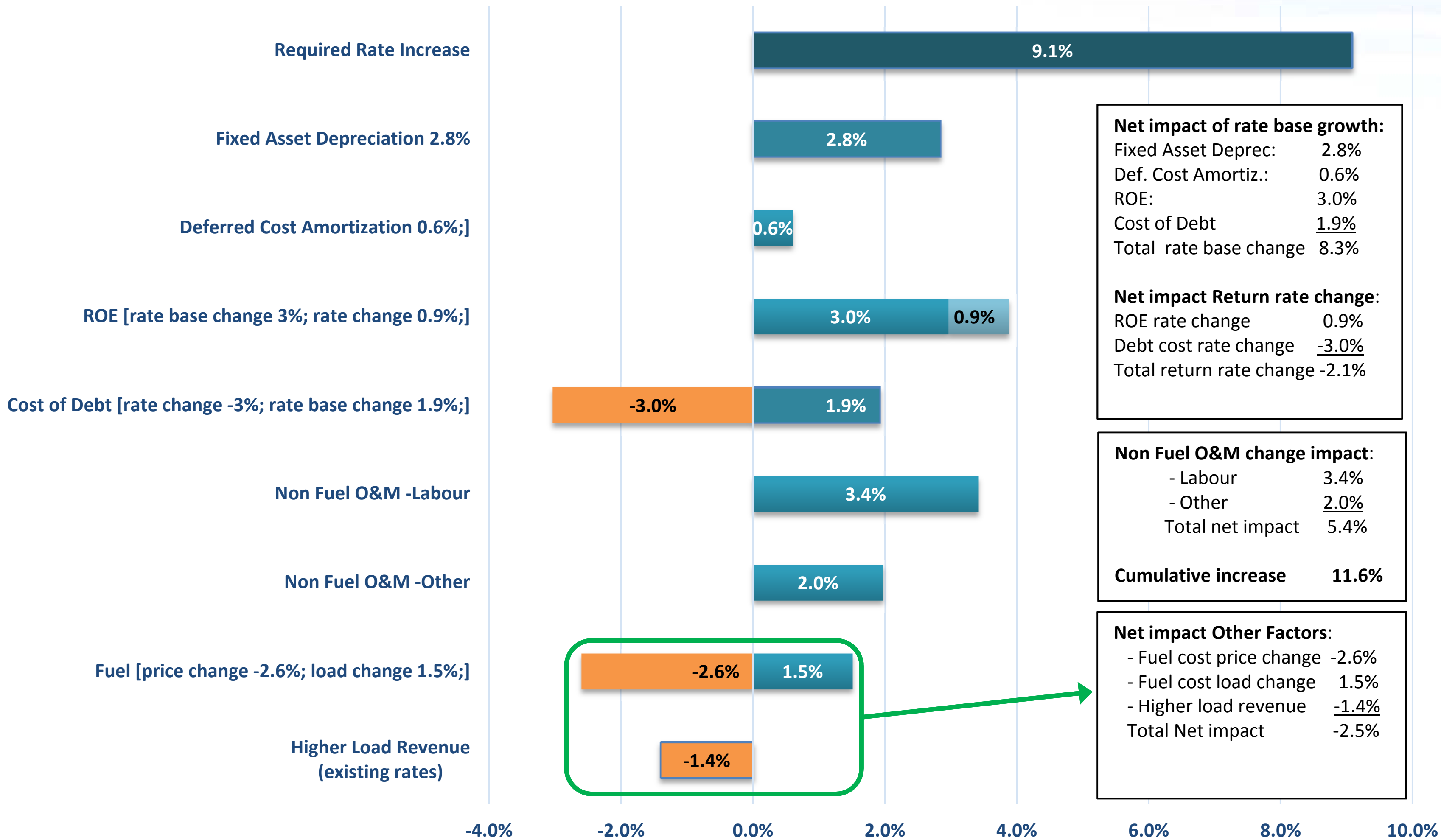


Drivers for GRA

Savings from Fuel Price Reductions, Use of Lower Cost LNG, Higher Load Revenues

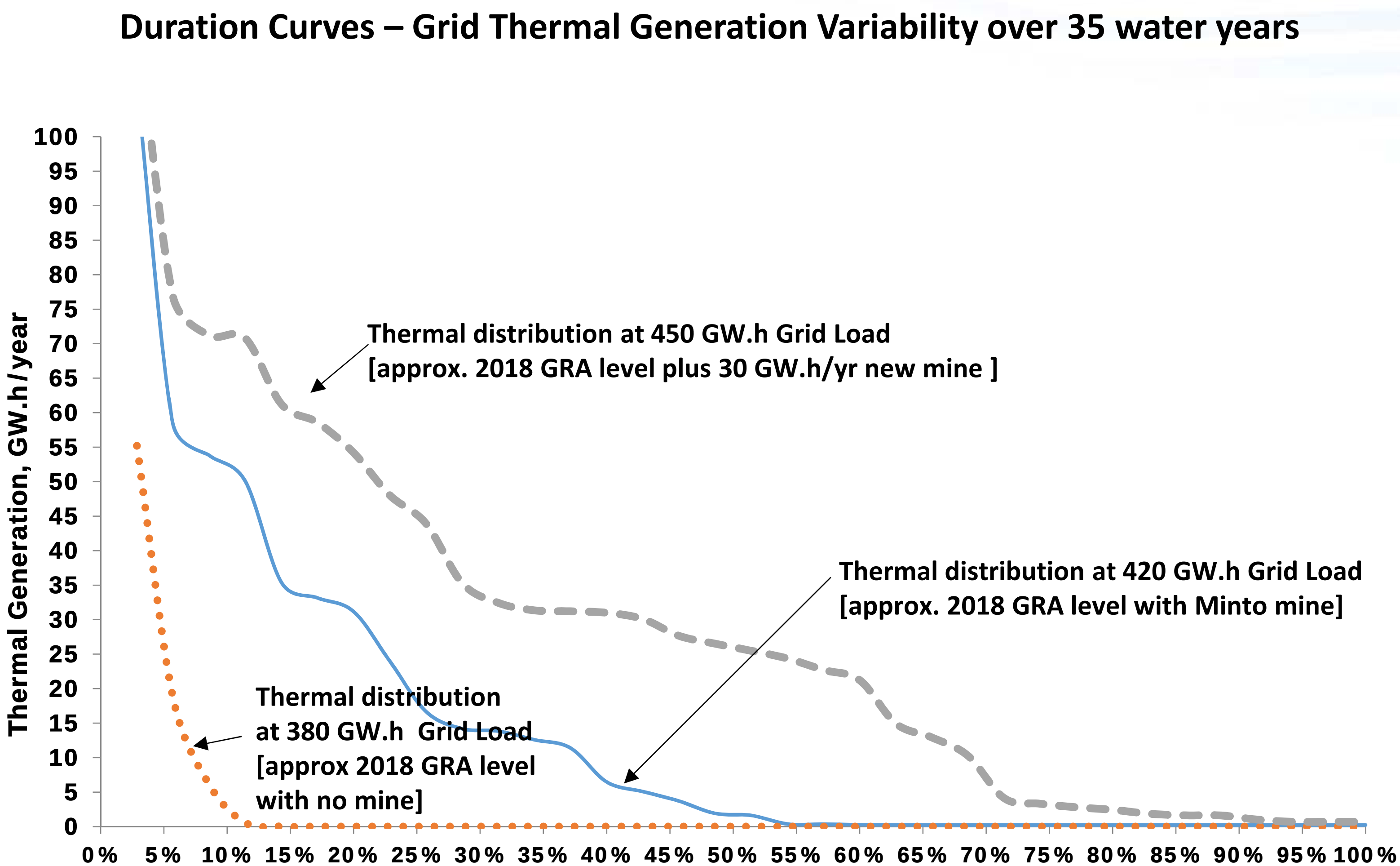
- ✓ Fuel Cost decreases of $0.79 million since 2013, determined as follows:

Fuel cost change – 2018 proposed vs 2013 approved	($ millions)
Volume Variance [Change in LTA thermal x 2013 Avg Cost]	$1.09
Rate Variance [2018 volumes x Avg Cost differential]	-$1.88
Net Impact to rates (1.1%)	-$0.79

- ✓ Higher load revenues from volume variance - $1.02 million
- ✓ Rate variance - $1.5 million LNG impact

Drivers for GRA

Thermal Generation Implications



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Other Matters
Diesel Contingency Fund Updates

The following DCF-related updates are addressed for 2017/18 GRA (Appendix 3.4)

- **Revised DCF Term Sheet (Attachment 3.4.1)**
  - General LTA YECSIM model determination updates to Table 3.4-1 for added water years (35 vs 28 years) and other water flow changes (e.g., Mayo flows), wind information, and Fish Lake hydro information
  - Updates to include LNG in ongoing annual DCF determinations to reflect GRA (LNG generation at 90% of LTA thermal; diesel generation at 10% LTA thermal; LNG delivered price per kW.h and diesel price per kW.h per GRA).
- **Potential Thermal Generation Variability (GW.h/yr) Depending on 35 years Water Conditions – Loads 380-450 GW.h/yr (Attachment 3.4.2)**
- **Information on YECSIM Model (Attachment 3.4.3)**
- **DCF Cap Option Assessment (Attachment 3.4.4)**
  - Updated analysis for Board & interveners on adequacy of existing DCF cap
  - Review benefits of higher cap (+/-$16 million vs. current +/-$8 million cap)
    - Increase years not needing rate riders;
    - reduce drought year rate rider charges

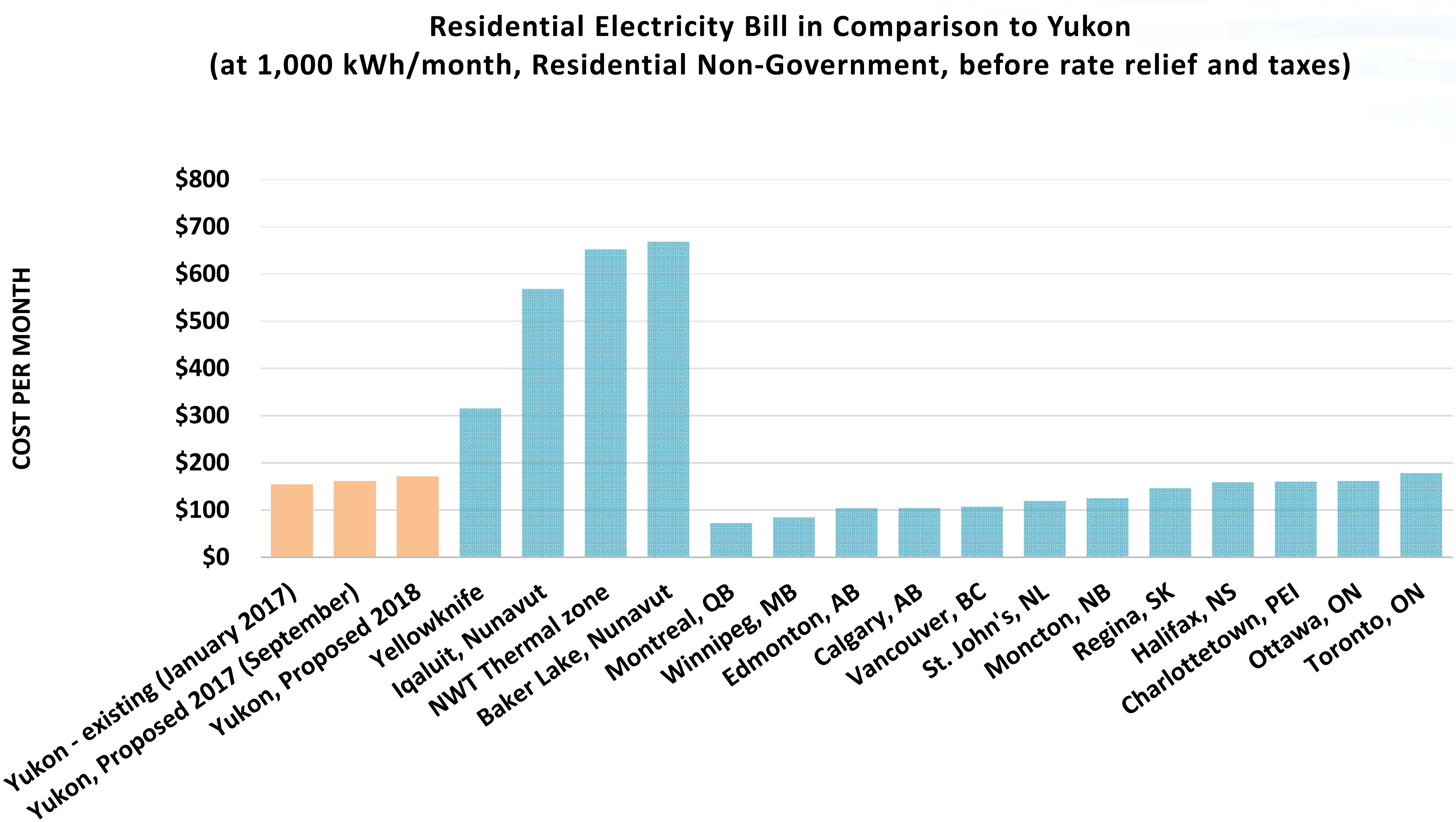
Other Matters

DCF Cap Option Impacts – 420 and 450 GW.h/yr loads with Minto mine

	420 GW.h/year load (13.9 GW.h/yr LTA thermal)		450 GW.h/yr load (28.6 GW.h/yr LTA thermal)	
	"+/-" DCF Cap ($million)		"+/-" DCF Cap ($million)	
	8	**16**	**8**	**16**
	Table 3.4-6A	Table 3.4-6B	Table 3.4-7A	Table 3.4-7B
DCF at 90% LNG and 10% Diesel				
Number of water years (out of 35) with				
No rate rider impact	16	21	20	26
Rider rebates	12	8	8	4
Max rebate	8	6	1	1
Rider charges	7	6	7	5
Rider Impact ($M/yr)				
Max Rebate	-2.16	-2.16	-5.06	-4.14
Peak Charge	13.63	4.67	14.00	8.24
Average charge year	4.18	2.20	4.82	3.54
Net impact after 35 yrs	5.90	-2.10	8.00	5.06

Other Matters

Yukon Rates Remain Competitive



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