

## AESO Quarterly Stakeholder Report

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# Q4 2017

- Initiative Updates
- Financial Highlights

## Quarterly Stakeholder Report – Fourth Quarter (October – December) 2017

The purpose of this section of the quarterly report is to provide stakeholders with an update on the Alberta Electric System Operator's (AESO) progress on the initiatives outlined in its 2017-2018 Business Plan and Budget Proposal (Business Plan). The reader of this report should reference the Business Plan published on the AESO's website for additional information to fully understand the various progress updates provided.

### I. Reporting on Business Plan Initiatives by Activity Group

| Electric System Operations  |   |   |   |
|---|---|---|---|
| Business Initiative   | Current Status  | Next Milestone  | Target  |
| <b>Alberta Reliability Standards (ARS) Critical Infrastructure Protection (CIP)</b>                 | AESO became CIP compliant as of October 1, 2017   | None  | Complete Western Electricity Coordinating Council (WECC) CIP audit of AESO compliance with standards in Q1 2018 |
|   | ARS CIP Standard CIP-014-AB-02 (Physical Security) drafting complete  | CIP-PLAN for CIP-014 implementation to be drafted.<br><br>Stakeholder engagement for proposed ARS CIP-014 and CIP-PLAN expected in 2018 | CIP-014 standard expected to be filed with the Alberta Utilities Commission (AUC) in 2018                       |
| <b>Alberta Interconnected Electrical System (AIES) - enhancements (reliability and integration)</b> | Energy Management System (EMS) Upgrade Project completed in Q4 2017   | None  | None  |
|   | Wide Area Network (WAN) fully operational in Q4 2017  | None  | None  |
|   | SCC Expansion Project (implementation phase): Construction contract underway; and construction planning in progress | Site mobilization to occur in Q1  | Initiate construction in Q2   |

| Electric System Development  |   |   |  |
|--|---|---|--|
| Business Initiative  | Current Status  | Next Milestone  | Target   |
| <b>Advance system and regional transmission projects identified in the LTP</b> | Facility Application (FA) filed for the Calgary Downtown Reinforcement Project by ENMAX on November 30, 2017  | AUC decision on the Calgary Downtown Reinforcement Project is expected in Q2 2018     | Ongoing  |
|  | The Provost to Edgerton and Nilrem to Vermillion (PENV) written hearing concluded in Q4 2017  | AUC decision of PENV NID filing expected in Q1 2018                                   | Ongoing  |
|  | AESO filed the Rycroft Transmission Reinforcement NID, a component of the NW transmission plan in Q4 2017   | AUC decision on the Rycroft Transmission Reinforcement project is expected in Q2 2018 | Ongoing  |
|  | AESO will complete design and development of Chapel Rock-Castle Rock Ridge project requirements and initiate stakeholder engagement by Q1 2018  | Ongoing   | Ongoing  |
| <b>Intertie Restoration</b>  | AESO will complete design and development of intertie requirements and initiate stakeholder engagement by Q1 2018   | AESO will work with the TFO on public consultation and stakeholder engagement         | Ongoing  |
| <b>Competitive Process (for transmission)</b>                                  | A debt funding competition for the Fort McMurray West 500 kV Transmission Project (West Project) was conducted in June/July 2017. The West Project has successfully reached financial close and is currently under construction | None  | Target in-service date for the West Project is 2019        |
|  | Based on the current economic environment and sustained low oil prices, the AESO is deferring the launch date of the Fort McMurray East 500kV Transmission Project (East Project)   | None  | Reassessment of launch date of the East Project is ongoing |

| Electric System Development - continued    |   |   |   |
|--|---|---|---|
| Business Initiative                        | Current Status  | Next Milestone  | Target  |
| <b>Tariff rate information and updates</b> | In Q3 2017, the AESO filed the Rider C, <i>Deferral Account Adjustment Rider</i> , amendment application for changes to Rider C and the deferral account reconciliation methodology on an interim refundable basis. This application was filed as part of the 2018 ISO tariff application. Approval was provided by the Alberta Utilities Commission (AUC) on an interim basis in Q4 2017 with a Q1 2018 implementation | Approval of Rider C and deferral account methodology on a final basis in 2018/19  | The AESO plans to file with the AUC the 2016 deferral account reconciliation application in 2018  |
|  | In Q3 2017, the AESO filed the 2018 ISO tariff application (formerly referred to as the 2017 ISO Tariff Application)  | The AUC suspended this proceeding to allow the AESO time to consult on the coincident metered demand rate design issue and distribution facility owner customer contribution issue. A revised application or status update is due to the Commission by the AESO by March 30, 2018 | Ongoing   |
|  | In Q3 2017, the AESO filed its Transmission Rate Projection (TRP) model with the 2018 ISO Tariff Application  | With the 2017 Long-term Plan published, the AESO plans to update the Transmission Rate Projection factsheet and file the updated TRP model with the AUC   | An updated TRP model, to incorporate the next Long Term Plan (LTP) results, will be published and filed with the AUC after the LTP is published in 2018 |
|  | In Q3 2017, the AESO filed the 2018 ISO tariff <u>update</u> application. Approval was provided by the Alberta Utilities Commission in Q4 2017 on a final basis   | Updated rates, investment, and tariff information documents to be implemented for Q1 2018   | Updated bill estimator information document to be posted to AESO website in Q1 2018.  |

| Customer Access Services  |  |  |   |
|---|--|--|---|
| Business Initiative   | Current Status   | Next Milestone   | Target  |
| <b>Advance customer connection projects within the connection queue<sup>1</sup></b> | AESO facilitating the advancement of approved System Access Service Requests for customer connection projects  | Support customer projects facilitating the in-service date (ISD) | Ongoing support of customer FAs, certifications and FA hearings |
|   | 49 customer energizations (including Connection, Contract and Behind-the-Fence projects) completed as of December 31, 2017   | Ongoing  | Ongoing   |
|   | 12 customer connection Abbreviated Need Identification Documents (ANID)s filed with the AUC (none of which were Market Participant Choice projects) and 1 Abbreviated Needs Approval Process (ANAP) customer connection projects were approved as of December 31, 2017 | NID development and filings as per schedule                      | Ongoing   |

<sup>1</sup> See [www.aeso.ca](http://www.aeso.ca) > Grid > Connecting to the grid > Connection project list - for a complete list of projects in the connection queue and the current status.

| Market Development  |   |  |  |
|---|---|--|--|
| Business Initiative   | Current Status  | Next Milestone   | Target   |
| <b>Market system replacement and re-engineering (MSR) project</b> | Successfully completed medium-term sustainment measures for 2017  | Not applicable   | Not applicable   |
| <b>Climate change program</b>                                     | <p>AESO launched the first Renewable Electricity Program (REP) competition - REP Round 1 in Q1 2017</p> <p>In Q4 2017, the AESO announced REP Round 1 successfully delivered nearly 600 MW of wind generation at a weighted average bid price of \$37/MWh</p> | <p>In February 2018, the Government of Alberta announced REP Rounds 2 and 3</p> <p>The Minister of Energy has directed the AESO to provide competition proposals for both rounds by the end of February 2018.</p> <p>The AESO anticipates opening REP Rounds 2 and 3 prior to the end of Q1 2018 with a Request for Expressions of Interest stage for each round</p> | <p>The target in-service date for REP Round 1 projects is Q4 2019</p> <p>The AESO plans to award Renewable Electricity Support Agreements associated with REP Rounds 2 and 3 by the end of Q4 2018</p> |
| <b>Capacity Market</b>  | AESO consulting with stakeholders to develop Capacity Market Design   | Development of first draft of AESO's Comprehensive Market Design (CMD) proposal by January 2018. Engagement with consolidated stakeholder working groups in February 2018  | Design complete by Q2 2018   |

## II. Financial Update – As of December 31, 2017

### Transmission Operating Costs (\$ million) – by accounting month

|                                     | 2017<br>Actual | 2017<br>Forecast | 2016<br>Actual |
|-------------------------------------|----------------|------------------|----------------|
| Wires costs                         | 1,685.1        | 1,729.3          | 1,497.6        |
| Operating reserves                  | 80.7           | 88.2             | 66.4           |
| Transmission line losses            | 50.7           | 74.1             | 43.5           |
| Other ancillary service costs       | 34.2           | 30.7             | 27.4           |
| <b>Transmission operating costs</b> | <b>1,850.7</b> | <b>1,922.2</b>   | <b>1,634.9</b> |

*Numbers may not add due to rounding*

**Wires costs** – Wires costs represent the amounts paid primarily to transmission facility owners (TFOs) in accordance with their Alberta Utilities Commission (AUC)-approved tariffs and are not controllable costs of the AESO.

Wires costs in 2017 are \$1,685.1 million, which is \$187.5 million or 13 per cent higher than the 2016 costs of \$1,497.6 million due to higher regulated rates charged by the TFOs for the current year (\$287 million) offset by adjustments related to prior production years (\$99 million). The AESO understands that the higher TFO tariffs reflect capital and operating costs associated with projects providing additional transmission system capacity, as well as higher costs to operate and maintain existing transmission facilities.

The wire costs for 2017 of \$1,685.1 are \$44.2 million or 3% less than the 2017 forecast of \$1,729 due to costs reductions related to prior years that are included in 2017 costs.

The 2017 forecast was based on TFO tariffs approved or applied-for as of October 20, 2016 with the forecast reflecting: i) compliance filings for 2016 tariffs; ii) compliance filings for 2017 tariffs; or iii) AUC approvals for 2017 tariffs. The 2017 wires costs reflect current AUC decisions.

**Operating reserves** – Operating reserves are generating capacity or load that is held in reserve and made available to the System Controller to manage the transmission system supply-demand balance in real time. Operating reserves are procured through an online, day-ahead exchange, where offer prices are indexed to the pool price. While the prices of operating reserves procured through the online exchange are indexed to the pool price, changes to the average pool price do not result in proportional changes to the operating reserve costs; the pool price for each hour has a significant impact on the operating reserve costs for that hour.

Operating reserve costs in 2017 are \$80.7 million, which is \$14.3 million or 22 per cent higher than the 2016 costs of \$66.4 million. The cost of operating reserves is impacted by actual volumes, hourly pool prices and operating reserve prices. The average hourly pool price is \$22 per megawatt hour (MWh) in 2017 compared to \$18 per MWh in 2016, representing an increase of 22 per cent. Operating reserve volumes financially settled in 2017 are 7,712 gigawatt hours (GWh) compared to 7,359 GWh in 2016, representing a five per cent increase. The cost variance is mainly attributable to higher pool prices, higher volumes and changes to offer behavior.

The 2017 operating reserve costs of \$80.7 are \$7.5 million or 9% lower than the forecast of \$88.2 million. The lower operating reserve costs are due to the actual average hourly pool price of \$22 per megawatt hour (MWh) in 2017 compared to \$32 per MWh forecasted pool price for 2017 resulting in lower operating reserve prices and costs. Actual operating reserve volumes were five percent higher than the forecast for 2017. The active operating reserves from May to July 2017 were impacted by higher imports on the AB-BC intertie which required higher volumes of operating reserves.

**Transmission line losses** – Transmission line losses represent the volume of energy that is lost as a result of electrical resistance on the transmission lines. Volumes associated with line losses are determined through the energy market settlement process as the difference between generation and import volumes, less consumption and export volumes. The hourly volumes of line losses vary based on load and export levels, generation (baseload, peaking units and imports) available to serve load, weather conditions, and changes in the transmission topology. System maintenance schedules, unexpected failures, dispatch decisions on the Alberta interconnected electric system (AIES), and short-term system measures (such as demand response) may also affect the volume of losses. The value of line losses is calculated based on the hourly pool price.

The cost of transmission line losses in 2017 is \$50.7 million, which is \$7.2 million or 17 per cent higher than the 2016 cost of \$43.5 million due to the impact of a 22 per cent higher average pool price and higher line loss volumes in 2017. Line loss volumes financially settled in 2017 are 2,222 GWh compared to 2,165 GWh in 2016, representing a three per cent increase.

The cost of transmission line losses in 2017 is \$50.7 million, which is \$23.4 million or 32 per cent lower than the 2017 forecast of \$74.1 million due to the impact of a 31 per cent lower average pool price than was forecasted.

**Other ancillary services costs** – The AESO procures other ancillary services for the secure and reliable operation of the AIES. These services are procured through a competitive procurement process where possible, or in instances where such procurement processes may not be feasible, through bilateral negotiations.

#### Other Ancillary Services Costs (\$ million) – by accounting month

|                                       | 2017<br>Actual | 2017<br>Forecast | 2016<br>Actual |
|---------------------------------------|----------------|------------------|----------------|
| Load shed service for imports         | 22.9           | 18.1             | 18.2           |
| Transmission must-run                 |                |                  |                |
| Contracted                            | 3.0            | 2.8              | -              |
| Conscripted                           | 0.5            | 2.0              | 1.3            |
| Reliability services                  | 2.9            | 2.9              | 2.9            |
| Poplar Hill                           | 2.8            | 2.8              | 2.8            |
| Black start                           | 2.1            | 2.1              | 2.1            |
| Transmission constraint rebalancing   | 0.0            | 0.1              | 0.0            |
| <b>Total Other ancillary services</b> | <b>34.2</b>    | <b>30.7</b>      | <b>27.4</b>    |

*Numbers may not add due to rounding*

Load shed service for imports (LSSi) is interruptible load that can be armed to trip, either automatically or manually, on the loss of the Alberta-British Columbia intertie to allow for increased import available transfer capability (ATC). LSSi costs are impacted by volume availability, contract prices and AIES system requirements for arming and tripping requirements. Actual costs in 2017 are higher than forecast due to a higher number of arming events required for operational purposes and higher volume availability.

Transmission must-run (TMR) occurs when generation is required to mitigate the overloading of transmission lines associated with line outages, system conditions in real time or the loss of generation in an area. In circumstances when this service is required for an unforeseeable event and there is no contracted TMR, non-contracted generators may be dispatched to provide this service (referred to as conscripted TMR).

Reliability services are provided through an agreement with Powerex Corp. for grid restoration balancing support in the event of an Alberta blackout and emergency energy in the event of supply shortfall.



The Poplar Hill generator provides voltage support (VARs) in addition to power (MW), to support the transmission system reliability in the Northwest part of the province.

Black start services are provided by generators that are able to restart their generation facility with no outside source of power. In the event of a system-wide black-out, black start services are used to re-energize the transmission system and provide start-up power to generators who cannot self-start. Black start providers are required in specific areas of the AIES to ensure the entire system has adequate start-up power.

Transmission constraint rebalancing costs are incurred when the transmission system is unable to deliver electricity from a generator to a given electricity consuming area without contravening reliability requirements. When this occurs, a market participant downstream of a constraint may be dispatched for purposes of transmission constraint rebalancing under the Independent System Operator (ISO) Rules and would receive a transmission constraint rebalancing payment for energy provided for that purpose.

### Other Industry Costs (\$ million)

|   | 2017<br>Actual | 2017<br>Forecast | 2016<br>Actual |
|---|----------------|------------------|----------------|
| Alberta Utilities Commission (AUC) fee – Transmission | 11.8           | 12.6             | 12.1           |
| AUC fee – Energy Market                               | 6.0            | 6.9              | 6.6            |
| WECC/NWPP costs                                       | 2.2            | 2.2              | 2.5            |
| Regulatory process costs                              | 1.2            | 1.5              | 1.4            |
| <b>Total other industry costs</b>                     | <b>21.2</b>    | <b>23.2</b>      | <b>22.6</b>    |

*Numbers may not add due to rounding*

Other industry costs represent fees or costs paid based on regulatory requirements or membership fees for industry organizations, which are not under the direct control of the AESO. These costs relate to the annual administration fee for the AUC, the AESO's share of Western Electricity Coordinating Council (WECC) and Northwest Power Pool (NWPP) membership fees and regulatory process costs. Regulatory process costs are associated with the AESO's involvement in an AUC proceeding to hear objections and complaints to ISO Rules or a regulatory application and costs incurred to respond to specific agency-related directions or recommendations that are beyond the routine operations of the AESO; this does not include application preparation costs.

Other industry costs in 2017 are \$21.2 million, which is \$1.4 million or six per cent lower than 2016 costs of \$22.6 million. The decrease is mainly attributable to lower AUC fees in 2017.

### General and Administrative Costs (\$ million)

|   | <b>2017<br/>Actual</b> | <b>2017<br/>Budget</b> | <b>2016<br/>Actual</b> |
|---|------------------------|------------------------|------------------------|
| Staff costs                             | 67.3                   | 65.0                   | 66.4                   |
| Contract services and consultants       | 13.3                   | 10.9                   | 9.0                    |
| Facilities                              | 6.9                    | 7.0                    | 7.0                    |
| Administration                          | 3.9                    | 3.7                    | 4.3                    |
| Computer services and maintenance       | 10.2                   | 10.6                   | 9.3                    |
| Telecommunications                      | 1.4                    | 1.3                    | 1.5                    |
| <b>General and administrative costs</b> | <b>103.0</b>           | <b>98.5</b>            | <b>97.5</b>            |

*Numbers may not add due to rounding*

### Interest and Amortization (\$ million)

|  | <b>2017<br/>Actual</b> | <b>2017<br/>Budget</b> | <b>2016<br/>Actual</b> |
|--|------------------------|------------------------|------------------------|
| Amortization of intangible assets and<br>depreciation of property, plant and equipment | 20.4                   | 18.8                   | 24.3                   |
| Interest   | 0.5                    | 0.9                    | 0.8                    |

## Capital Expenditure Update – As of December 31, 2017

| <b>Capital Program (\$ million)</b>                              |                               |                             |                      |                    |                          |                        |   |
|--|-------------------------------|-----------------------------|----------------------|--------------------|--------------------------|------------------------|---|
|  | <b>Total Project Approved</b> | <b>Prior Year(s) Actual</b> | <b>Spent in 2017</b> | <b>ETC in 2017</b> | <b>ETC Future Yr.(s)</b> | <b>Total Cost Est.</b> | <b>Variance Approved to Total Cost Est.</b> |
| <b>Key Capital Initiatives <sup>2</sup></b>                      |                               |                             |                      |                    |                          |                        |   |
| CIP Implementation   | 1.1                           | 0.8                         | 0.1                  | 0.0                | 0.0                      | 0.9                    | 0.2   |
| IT/Cyber Security  | 2.9                           | 0.6                         | 1.3                  | 0.0                | 0.8                      | 2.7                    | 0.2   |
| MSR* Sustainment   | 3.0                           | -                           | 2.9                  | 0.0                | 0.1                      | 3.0                    | 0.0   |
| Market Evolution   | 0.6                           | -                           | 0.1                  | 0.0                | 0.5                      | 0.6                    | 0.0   |
| Facilities   | 1.4                           | -                           | 1.3                  | 0.0                | -                        | 1.3                    | 0.1   |
| <b>Other Capital Initiatives</b>                                 | 6.7                           | 2.6                         | 3.6                  | 0.0                | 0.9                      | 7.2                    | (0.5)                                       |
| <b>Life Cycle Funding</b>  | 6.2                           | -                           | 6.1                  | 0.0                | -                        | 6.1                    | 0.1   |
| <b>Subtotal General Capital</b>                                  | 21.9                          | 4.0                         | 15.3                 | 0.0                | 2.3                      | 21.7                   | 0.2   |
| <b>Major Project Capital – EMS** Implementation</b>              | 31.7                          | 22.6                        | 6.6                  | 0.0                | -                        | 29.2                   | 2.5   |
| <b>Major Project Capital – SCC*** Expansion – Implementation</b> | 21.9                          | -                           | 1.8                  | 0.0                | 19.9                     | 21.7                   | 0.2   |
| <b>Total Capital</b>   | 75.5                          | 26.6                        | 23.7                 | 0.0                | 22.2                     | 72.5                   | 3.0   |

Note: Differences may exist due to rounding

\* Market Systems Replacement and Re-engineering

\*\*Energy Management System

\*\*\* System Coordination Centre

### General Capital Program (\$ million)

|   |      |
|---|------|
| Spent to December 31, 2017                              | 15.3 |
| AESO Board Decision Document – general capital approved | 16.9 |
| Variance – underspent                                   | 1.6  |

<sup>2</sup> Section Appendix I - Notes which provide a summary of financial variances or changes to the (key) capital initiatives

## Appendix I - Notes

The following appendix provides further detail on major project progress for the key capital programs (e.g., approved business case or change-orders).

| Key Capital Initiatives                                     |                      |   |
|---|----------------------|---|
| <b>Reliability Program – Energy Management System (EMS)</b> | <b>Description</b>   | The EMS is used by System Controllers in grid operations to monitor, control and optimize the performance of the power system. The EMS is comprised of two major components the Application suite and IT Infrastructure. Both components have reached end of life and will no longer be supported by their respective vendors. In order to ensure reliable grid operations, be Critical Infrastructure Protection (CIP) compliant and have supported hardware and software, it was deemed prudent to proceed with an upgrade to the AESO EMS. |
|   | <b>2017 Progress</b> | The implementation phase of the EMS Upgrade project is a multi-year project which is proceeding to plan. The project was deployed into production in Q3 2017. Project completion in Q4 2017.<br><br>See Business Plans 2015-2017 Appendix F: Major Projects for more information.   |
|   | <b>2018 Plans</b>    | Sustainment and optimization phases will follow the completion of the implementation phase and related costs will form part of the AESO's ongoing general capital program.  |
| <b>Reliability Program - Other Components (non-EMS)</b>     | <b>Description</b>   | Grid management projects that are intended to enhance the efficiency and improve the ability to reliably run the Alberta Interconnected Electric System (AIES).   |
|   | <b>2017 Progress</b> | The primary focus for 2017 has been the continued phased migration of Transmission Facility Owners (TFOs) and Independent Power Producers (IPP) to the new network for the Supervisory Control and Data Acquisition (SCADA)/Wide Area Network (WAN) communications service which became fully operational in Q4 2017  |
|   | <b>2018 Plans</b>    | Not applicable - complete   |

| Key Capital Initiatives  |                      |   |
|--|----------------------|---|
| <b>Alberta Reliability Standards Critical Infrastructure Protection (CIP) Implementation</b> | <b>Description</b>   | Implementation of facility upgrades, changes to AESO sites and/or systems that are required to support CIP V5 implementation and compliance requirements.   |
|  | <b>2017 Progress</b> | Implemented CIP processes, security controls and system changes required to ensure compliance readiness including: implementation of various physical security system upgrades.   |
|  | <b>2018 Plans</b>    | Institutionalize the AESO sustainment program for compliance with CIP standards. Apply efficiencies and optimizations to the AESO's CIP process to ensure sustainability.   |
| <b>IT / Cyber Security Advancements</b>  | <b>Description</b>   | Upgrade AESO systems and processes to reduce the risk of cyber security breaches and facilitate AESO compliance to CIP V5 requirements.   |
|  | <b>2017 Progress</b> | The first and second sets of enhancements to AESO's advanced threat management capabilities have been completed.  |
|  | <b>2018 Plans</b>    | Continue to advance the multi-year Identity and Access Management (IAM) projects.<br><br>Continued implementation of additional controls to prevent, detect, respond to, and recover from incidents.  |
| <b>Market Systems Replacement and Reengineering (MSR) - Implementation (Sustainment)</b>     | <b>Description</b>   | The MSR Implementation program is based on a multi-year phased approach designed to address the operating requirements of the AESO's market systems.<br><br>Many of these systems have been stretched past their useful life and in many cases, have become increasingly difficult and costly to change and operate reliably.<br><br>Focus is to sustain current market system reliability and security through medium-term measures. |
|  | <b>2017 Progress</b> | Successfully completed medium-term sustainment measures.  |
|  | <b>2018 Plans</b>    | Not applicable - complete   |

| Key Capital Initiatives |                      |  |
|-------------------------|----------------------|--|
| Market Evolution        | <b>Description</b>   | <p>The identification, development and implementation of tools in support of market optimization and/or performance improvements. This includes system changes for wind and solar aggregated generating facility forecasting rules, and system changes to enable increased flexibility for Operating Reserve (OR) procurement.</p> <p>Also included are system changes to support an evolving market due to implementation of a capacity market and increased amounts of renewables.</p> |
|                         | <b>2017 Progress</b> | <p>OR procurement system changes business case completed. Based on business case review, no system changes are required, at this time.</p> <p>Business case for system changes for Wind and Solar Aggregated Generating Facility Forecasting rules completed and approved.</p>   |
|                         | <b>2018 Plans</b>    | <p>Implement system changes supporting the Wind and Solar Aggregated Generating Facility Forecasting Rules by the end of Q2 2018.</p> <p>Implement tools to support development of capacity market demand curve and develop high level design for capacity market auction tools.</p>   |
| Facilities              | <b>Description</b>   | Implement physical access control (security) improvements at the System Coordination Centre (SCC) to enhance security and safety for personnel. Supports SCC Expansion initiative.   |
|                         | <b>2017 Progress</b> | Project completed  |
|                         | <b>2018 Plans</b>    | Not applicable - complete  |
| <b>Key Initiatives</b>  |                      | <p><b>2017 Budget \$6.4 million</b></p> <p><b>2018 Budget \$4.5 million</b></p>  |