AESO 2017 ISO Tariff Application

Appendix E – Amended Rates DTS, FTS, DOS, XOS, XOM, PSC and STS, Rider J and Section 8

Rates

Rate DTS	Demand Transmission Service
Rate FTS	Fort Nelson Demand Transmission Service
Rate DOS	Demand Opportunity Service
Rate XOS	Export Opportunity Service
Rate XOM	Export Opportunity Merchant Service
Rate PSC	Primary Service Credit
Rate STS	Supply Transmission Service

Riders

Rider J	Wind Forecasting Service Cost Recovery Rider

Terms and Conditions

Section 8	Construction Contributions for Connection Projects

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ISO Tariff – Rate DTS
Demand Transmission Service

Applicability

1 Rate DTS applies to **system access service** provided at a **point of delivery** to:

(a) the **legal owner** of an **electric distribution system**;

(b) a **person** who has entered into an arrangement directly with the **ISO** for the provision of **system access service** under subsection 101(2) of the **Act**;

(c) the **legal owner** of an industrial system that has been designated as such by the **Commission**; or

(d) the City of Medicine Hat.

Rate

2 The **ISO** must determine the charge under Rate DTS in a **settlement period** in accordance with subsections 3 through 7 below as the sum of the connection charge, the **operating reserve** charge, the **transmission constraint rebalancing** charge, the voltage control charge and the other system support services charge.

Connection Charge

3(1) The **ISO** must determine the connection charge as the sum, over all rows, of the products calculated by multiplying the volume and charge in each row (a) through (i) of the following table.

Volume in **Settlement Period**	Charge
Bulk System Charge	
(a) Coincident **metered demand**	$~~10,175.00~~10,670.00/ MW/**month**
(b) **Metered energy**	$~~1.17~~1.25/MWh
Regional System Charge	
(c) **Billing capacity**	$~~2,333.00~~2,356.00/MW/**month**
(d) **Metered energy**	$~~0.81~~0.87/MWh
Point of Delivery Charge	
(e) **Substation fraction**	$~~8,604.00~~8,789.00/**month**
(f) First (7.5 × **substation fraction**) MW of **billing capacity**	$~~3,484.00~~3,559.00/MW/**month**
(g) Next (9.5 × **substation fraction**) MW of **billing capacity**	$~~2,182.00~~2,229.00/MW/**month**

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Volume in **Settlement Period**	Charge
(h) Next (23 × **substation fraction**) MW of **billing capacity**	$~~1,522.00~~1,555.00/MW/**month**
(i) All remaining MW of **billing capacity**	$~~986.00~~1,007.00/MW/**month**

(2) The **ISO** must determine the coincident **metered demand** as the **metered demand** at the **point of delivery** averaged over the 15-minute interval in which the sum of the **metered demands** for all Rate DTS and Rate FTS **market participants** is greatest in the **settlement period**.

Operating Reserve Charge

4(1) The **ISO** must determine the **operating reserve** charge as the sum, over all hours in the **settlement period**, of the amount calculated in each hour as the product of:

(a) **metered energy** for the Rate DTS **market participant** in the hour; and

(b) the total cost of **operating reserves** in the hour divided by the total **metered energy** for all Rate DTS and Rate FTS **market participants** in the hour.

(2) The **ISO** must estimate the **operating reserve** charge, if unable to determine it for a **settlement period** in accordance with subsection 4(1) above, as the sum, over all hours in the **settlement period**, of the amount calculated in each hour as the product of:

(a) **metered energy** for the Rate DTS **market participant** in the hour; and

(b) **pool price** in the hour multiplied by ~~6.66~~6.99%.

Transmission Constraint Rebalancing Charge

5 The **ISO** must determine the **transmission constraint rebalancing** charge as the sum, over all hours in the **settlement period**, of the amount calculated in each hour as the product of:

(a) **metered energy** for the Rate DTS **market participant** in the hour; and

(b) the total cost of **transmission constraint rebalancing** payments in the hour divided by the total **metered energy** for all Rate DTS and Rate FTS **market participants** in the hour.

Voltage Control Charge

6 The **ISO** must determine the voltage control charge as the product of **metered energy** in the **settlement period** multiplied by $~~0.06~~0.07/MWh.

Other System Support Services Charge

7 The **ISO** must determine the other system support services charge as the sum of:

(a) the highest **metered demand** in the **settlement period** multiplied by $46.00/MW/**month**; and

(b) when **power factor** is less than 90% during the interval of highest **metered demand** in the **settlement period**, $400.00/MVA multiplied by the **apparent power** difference calculated during the interval of highest **metered demand** in the **settlement period** as the difference between the metered **apparent power** and 111% of **metered demand**.

Terms

8(1) The **ISO** must apply Rate DTS separately at each **point of delivery**, except where Rate DTS applies to totalized **points of delivery** under subsection 5 of section 13 of the **ISO tariff**.

(2) The **ISO** must determine **metered energy** under Rate DTS, in an hour for which a Rate DOS transaction has been approved by the **ISO** at a **point of delivery** where Rate DOS applies, as the sum of:

(a) **metered energy** up to the Rate DTS **contract capacity**; plus

(b) any additional **metered energy** determined under subsection 2(2) of Rate DOS.

(3) The **ISO** must apply Rider C, *Deferral Account Adjustment Rider*, to **system access service** provided under this rate.

(4) The **ISO** must apply Rider F, *Balancing Pool Consumer Allocation Rider*, to **system access service** provided under this rate.

(5) The terms and conditions of the **ISO tariff** form part of this rate.

Revision History

Effective	Description
2017-xx-01	Updated rate levels applied for as part of 2017 Tariff Update Application
2016-04-01	Updated charges, as approved in **Commission** Decision 21302-D01-2016 issued on March 31, 2016
2016-01-01	Updated charges, as approved in **Commission** Decision 20753-D02-2015 issued on December 21, 2015
2015-11-26	Updated subsections and charges, as approved in **Commission** Decision 20623-D01-2015 issued on November 5, 2015
2015-07-01	Updated subsections and charges, as approved in **Commission** Decision 3473-D01-2015 issued on June 17, 2015
2013-10-01	Updated charges, as approved on an interim refundable basis in **Commission** Decision 2013-325 issued on August 28, 2013 and on a final basis in **Commission** Decision 2014-242 issued on August 21, 2014.
2011-07-01	Revised and reformatted all subsections, as approved in **Commission** Decision 2011-275 issued on June 24, 2011.

Applicability

1 Rate FTS applies to **system access service** provided at the **point of delivery** to BC Hydro at Fort Nelson, British Columbia:

Rate

2 The **ISO** must determine the charge under Rate FTS in a **settlement period** in accordance with subsections 3 through 7 below as the sum of the connection charge, the **operating reserve** charge, the **transmission constraint rebalancing** charge, the voltage control charge and the other system support services charge.

Connection Charge

3(1) The **ISO** must determine the connection charge as the sum, over all rows, of the products calculated by multiplying the volume and charge in each row (a) through (d) of the following table.

Volume in **Settlement Period**	Charge
Bulk System Charge	
(a) Coincident **metered demand**	$~~10,175.00~~10,670.00/ MW/**month**
(b) **Metered energy**	$~~1.17~~1.25/MWh
Regional System Charge	
(c) **Billing capacity**	$~~2,333.00~~2,356.00/MW /**month**
(d) **Metered energy**	$~~0.81~~0.87/MWh

(2) The **ISO** must determine the coincident **metered demand** as the **metered demand** at the **point of delivery** averaged over the 15-minute interval in which the sum of the **metered demands** for all Rate DTS and Rate FTS **market participants** is greatest in the **settlement period**.

(3) The **ISO** must determine the rate for the regional system charge in subsections 3(1)(c) and 3(1)(d) above as the greater of:

(a) the rate for the regional system charge in subsections 3(1)(c) and 3(1)(d) of Rate DTS; or

(b) a specific Fort Nelson rate based on the levelized cost of the original ATCO Electric line providing service to Fort Nelson.

Operating Reserve Charge

4(1) The **ISO** must determine the **operating reserve** charge as the sum, over all hours in the **settlement period**, of the amount calculated in each hour as the product of:

(a) **metered energy** for the Rate FTS **market participant** in the hour; and

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(b) the total cost of **operating reserves** in the hour divided by the total **metered energy** for all Rate DTS and Rate FTS **market participants** in the hour.

(2) The **ISO** must estimate the **operating reserve** charge, if unable to determine it for a **settlement period** in accordance with subsection 4(1) above, as the sum, over all hours in the **settlement period**, of the amount calculated in each hour as the product of:

(a) **metered energy** for the Rate FTS **market participant** in the hour; and

(b) **pool price** in the hour multiplied by ~~6.66~~6.99%.

Transmission Constraint Rebalancing Charge

5 The **ISO** must determine the **transmission constraint rebalancing** charge as the sum, over all hours in the **settlement period**, of the amount calculated in each hour as the product of:

(a) **metered energy** for the Rate FTS **market participant** in the hour; and

(b) the total cost of **transmission constraint rebalancing** payments in the hour divided by the total **metered energy** for all Rate DTS and Rate FTS **market participants** in the hour.

Voltage Control Charge

6 The **ISO** must determine the voltage control charge as the sum of:

(a) the product of **metered energy** in the **settlement period** multiplied by $~~0.06~~0.07/MWh; and

(b) the sum, over all hours in the **settlement period** in which Rainbow area load exceeds 145 MW and transmission must-run generation is required in the Rainbow area, of the cost associated with transmission must-run generation in the Rainbow area in an hour multiplied by the ratio in the hour of:

(i) Fort Nelson load in excess of 38.5 MW; to

(ii) the sum of Fort Nelson load in excess of 38.5 MW and Alberta Rainbow area load (excluding Fort Nelson load) in excess of 106.5 MW.

Other System Support Services Charge

7 The **ISO** must determine the other system support services charge as the sum of:

(a) the highest **metered demand** in the **settlement period** multiplied by $46.00/MW/**month**; and

(b) when **power factor** is less than 90% during the interval of highest **metered demand** in the **settlement period**, $400.00/MVA multiplied by the **apparent power** difference calculated during the interval of highest **metered demand** in the **settlement period** as the difference between the metered **apparent power** and 111% of **metered demand**.

Terms

8(1) BC Hydro must, if it terminates the **system access service** provided under this rate prior to the full payment of the levelized cost of the original ATCO Electric line providing service to Fort Nelson under subsection 3(3)(b) above, pay the amount the **ISO** determines as the remaining unpaid balance of those costs net of any residual value, in addition to any **financial obligations** under section 9 of the **ISO tariff**.

(2) The **ISO** must apply Rider C, *Deferral Account Adjustment Rider*, to **system access service** provided under this rate.

(3) The terms and conditions of the **ISO tariff** form part of this rate.

Revision History

Effective	Description
2017-xx-01	Updated rate levels applied for as part of 2017 Tariff Update Application
2016-04-01	Updated charges, as approved in **Commission** Decision 21302-D01-2016 issued on March 31, 2016
2016-01-01	Updated charges, as approved in **Commission** Decision 20753-D02-2015 issued on December 21, 2015
2015-11-26	Updated subsections and charges, as approved in **Commission** Decision 20623-D01-2015 issued on November 5, 2015.
2015-07-01	Updated subsections and charges, as approved in **Commission** Decision 3473-D01-2015 issued on June 17, 2015.
2013-10-01	Updated charges, as approved on an interim refundable basis in **Commission** Decision 2013-325 issued on August 28, 2013 and on a final basis in **Commission** Decision 2014-242 issued on August 21, 2014
2011-07-01	Revised and reformatted all subsections, as approved in **Commission** Decision 2011-275 issued on June 24, 2011.

Applicability

1 Rate DOS applies to **system access service** provided at a **point of delivery** to a **market participant** who:

(a) receives **system access service** under Rate DTS, *Demand Transmission Service*;

(b) is eligible for **demand** opportunity service under section 12 of the **ISO tariff**; and

(c) is recallable in accordance with the provisions of this rate.

Metered Energy

2(1) The **ISO** must apply a Rate DOS charge to **metered energy** received at a **point of delivery** in every hour:

(a) for which a Rate DOS transaction has been approved by the **ISO**;

(b) above the Rate DTS **contract capacity** for the **system access service**; and

(c) up to the sum of the Rate DTS **contract capacity** and the approved Rate DOS transaction capacity for the **system access service**.

(2) The **ISO** must add to the **market participant**'s **metered energy** received at a **point of delivery** under Rate DTS any **metered energy** received at the **point of delivery** in an hour that exceeds the sum of the Rate DTS **contract capacity** and the approved Rate DOS transaction capacity for the **system access service,** in the same **settlement period**.

Rate

3(1) The **ISO** must provide the three types of **demand** opportunity service in accordance with the charges, recall **directive** response times and recall priorities in the following table.

Rate DOS Type	Rate DOS Charge	Recall **Directive** Response Time	Recall Priority
(a) DOS 7 Minutes	$~~4.71~~4.99/MWh	7 minutes	Before Rates DTS, FTS, DOS Term and DOS 1 Hour
(b) DOS 1 Hour	$~~15.38~~16.48/MWh	1 hour	Before Rates DTS, FTS and DOS Term
(c) DOS Term	$~~88.23~~94.85/MWh	7 minutes	Before Rates DTS and FTS

(2) The **ISO** must determine the amount billed for **demand** opportunity service in a **settlement period** as the greater of:

(a) (i) the Rate DOS charge from subsection 3(1)(a), 3(1)(b), or 3(1)(c) above, as applicable, multiplied by the **metered energy** during the **settlement period**; plus

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(ii) an incremental losses charge calculated as the sum, over all transaction hours in the **settlement period**, of **metered energy** in the hour multiplied by **pool price** in the hour multiplied by a **loss factor** for the facility, where the **loss factor** is determined in accordance with section 501.10 of the **ISO rules**, *Transmission Loss Factor Methodology and Requirements*, and is available to **market participants** in the **loss factors** section of the **ISO** website;

or

(b) a minimum amount equal to the Rate DOS charge from subsection 3(1)(a), 3(1)(b), or 3(1)(c) above, as applicable, multiplied by the approved Rate DOS transaction capacity multiplied by the number of hours in total transactions in the **settlement period** multiplied by 75%.

(3) The **ISO** must add a transaction fee of $500.00 to the amount billed for **demand** opportunity service in a **settlement period** in which the **ISO** approved at least one Rate DOS transaction at the **point of delivery**.

Terms

4(1) The **ISO** must apply Rate DOS separately at each **point of delivery**.

(2) The **market participant** must, if the **ISO** recalls a **market participant**'s **demand** opportunity service, curtail load by the amount directed by the **ISO** which:

(a) may be an amount up to the approved Rate DOS transaction capacity; and

(b) must not require curtailment below the **market participant**'s Rate DTS **contract capacity** for the **system access service**.

(3) The **market participant** must, in response to a **directive** from the **ISO**, achieve curtailment of its **demand** opportunity service load within the response time specified in subsection 3(1)(a), 3(1)(b), or 3(1)(c) above, as applicable.

(4) The **ISO** must apply Rider E, *Losses Calibration Factor Rider*, to **system access service** provided under this rate.

(5) The **ISO** must apply Rider F, *Balancing Pool Consumer Allocation Rider*, to **system access service** provided under this rate, with the exception of the City of Medicine Hat.

(6) The terms and conditions of the **ISO tariff** form part of this rate.

Revision History

Effective	Description
2017-xx-01	Updated rate levels applied for as part of 2017 Tariff Update Application
2016-04-01	Updated charges, as approved in **Commission** Decision 21302-D01-2016 issued on March 31, 2016
2016-01-01	Updated charges, as approved in **Commission** Decision 20753-D02-2015 issued on December 21, 2015
2015-07-01	Updated subsections and charges, as approved in **Commission** Decision 3473-D01-2015 issued on June 17, 2015 except for the losses charge component in subsection 3(2) approved on an interim basis in **Commission** Decision 2014-242 issued on August 21, 2014.
2013-10-01	Updated charges, as approved on an interim refundable basis in **Commission** Decision 2013-325 issued on August 28, 2014 and on a final basis, in **Commission** Decision 2014-242 issued on August 21, 2014 except for the losses charge component in subsection 3(2) approved on an interim basis in **Commission** Decision 2014-242 issued on August 21, 2014.
2011-07-01	Revised and reformatted all subsections, as approved in **Commission** Decision 2011-275 issued on June 24, 2011.

Applicability

1 Rate XOS applies to **system access service** provided to **market participants** who export electric energy from the **interconnected electric system** utilizing an **intertie** that existed on August 12, 2004, as referred to in section 16 of the *Transmission Regulation*..

Availability

2 The **ISO** must make export opportunity service available:

(a) only when sufficient capacity exists on the **transmission system** to accommodate the capacity scheduled for export; and

(b) a minimum of twenty-four (24) hours following execution of an agreement for **system access service** for export opportunity service.

Rate

3(1) The **ISO** must provide export opportunity service in accordance with the charge, recall **directive** response time and recall priority in the following table.

Rate	Charge	Recall **Directive** Response Time	Recall Priority
XOS	$~~7.12~~7.64/MWh	1 hour	Before Rates DTS, FTS and DOS (any type)

(2) The **ISO** must determine the amount billed for export opportunity service in a **settlement period** as the greater of:

(a) (i) the Rate XOS charge from subsection 3(1) above multiplied by the **market participant**'s export **interchange transaction** during the **settlement period**; plus

(ii) an incremental losses charge calculated as the sum, over all transaction hours in the **settlement period**, of the **market participant**'s export **interchange transaction** in the hour multiplied by **pool price** for the hour multiplied by a **loss factor** for the **intertie**, where the **loss factor** is determined in accordance with section 501.10 of the **ISO rules**, *Transmission Loss Factor Methodology and Requirements*, and is available to **market participants** in the **loss factors** section of the AESO website;

or

(b) a minimum amount calculated as the sum, over all transaction hours in the **settlement period**, of:

(i) the Rate XOS charge from subsection 3(1)(a) or 3(1)(b) above, as applicable, multiplied by the **market participant**'s hour-ahead scheduled capacity multiplied by 75%; plus

(ii) an incremental losses charge calculated as the **market participant**'s hour-ahead scheduled capacity multiplied by 75% multiplied by **pool price** for the hour multiplied by a **loss factor** for the **intertie**, where the **loss factor** is determined in accordance with section 501.10 of the **ISO rules**, *Transmission Loss Factor Methodology and*

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Requirements, and is available to **market participants** in the **loss factors** section of the AESO website.

(3) The **ISO** must add an **operating reserve** charge, an other system support services charge or both to the amount billed for export opportunity service in a **settlement period** when the transaction requires the **ISO** to procure incremental **operating reserves**, incremental system support services or both.

(4) The **ISO** must add a transaction fee of $500.00 to the amount billed for export opportunity service in a **settlement period** in which at least one Rate XOS transaction was approved for the **market participant**.

Terms

4(1) The **ISO** must apply Rate XOS separately at each **point of interconnection**.

(2) A **market participant** must achieve curtailment of its export opportunity service within the response time specified in subsection 3(1) above in response to a **directive** from the **ISO**.

(3) The **market participant** may contract for export opportunity service for a term within the minimum and maximum terms in the following table.

Rate	Minimum Term	Maximum Term
XOS	1 hour	1 **month**

(4) The **ISO** must apply Rider E, *Losses Calibration Factor Rider*, to **system access service** provided under this rate.

(5) The terms and conditions of the **ISO tariff** form part of this rate.

Revision History

Effective	Description
2017-xx-01	Updated rate levels applied for as part of 2017 Tariff Update Application
2016-04-01	Updated charges, as approved in **Commission** Decision 21302-D01-2016 issued on March 31, 2016
2016-01-01	Updated charges, as approved in **Commission** Decision 20753-D02-2015 issued on December 21, 2015
2015-07-01	Updated subsections and charges, as approved in **Commission** Decision 3473-D01-2015 issued on June 17, 2015 except for the losses charge component in subsection 3(2) approved on an interim basis in **Commission** Decision 2014-242 issued on August 21, 2014.
2013-10-01	Updated charges, as approved on an interim refundable basis in **Commission** Decision 2013-325 issued on August 28, 2014 and on a final basis, in **Commission** Decision 2014-242 issued on August 21, 2014 except for the losses charge component in subsection 3(2) approved on an interim basis in **Commission** Decision 2014-242 issued on August 21, 2014.

2011-07-01	Revised and reformatted all subsections, as approved in **Commission** Decision 2011-275 issued on June 24, 2011.

ISO Tariff – Rate XOM
Export Opportunity Merchant Service

Applicability

1 Rate XOM applies to **system access service** provided to **market participants** who export electric energy from the **interconnected electric system** utilizing a merchant **intertie**, defined in accordance with subsection 27(4) of the *Transmission Regulation* as an **intertie** for which the cost of planning, designing, constructing, operating and interconnecting is paid by the person who proposed the **intertie** and other persons that directly benefit from the **intertie**.

Availability

2 The **ISO** must make export opportunity merchant service available:

(a) only when sufficient capacity exists on the **transmission system** to accommodate the capacity scheduled for export; and

(b) a minimum of twenty-four (24) hours following execution of an agreement for **system access service** for export opportunity merchant service.

Rate

3(1) The **ISO** must provide export opportunity merchant service in accordance with the charge, recall **directive** response time and recall priority in the following table.

Rate	Charge	Recall **Directive** Response Time	Recall Priority
XOM	$~~7.12~~7.64/MWh	1 hour	Before Rates DTS, FTS and DOS (any type)

(2) The **ISO** must determine the amount billed for export opportunity merchant service in a **settlement period** as the greater of:

(a) the Rate XOM charge from subsection 3(1) above multiplied by the **market participant**'s export **interchange transaction** during the **settlement period**; or

(b) a minimum amount calculated as the sum, over all transaction hours in the **settlement period**, of the Rate XOM charge from subsection 3(1) above multiplied by the **market participant**'s hour-ahead scheduled capacity multiplied by 75%.

(3) The **ISO** must add an **operating reserve** charge, an other system support services charge or both to the amount billed for export opportunity merchant service in a **settlement period** when the transaction requires the **ISO** to procure incremental **operating reserves**, incremental system support services or both.

(4) The **ISO** must add a transaction fee of $500.00 to the amount billed for export opportunity merchant service in a **settlement period** in which at least one Rate XOM transaction was approved for the **market participant**.

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Terms

4(1) The **ISO** must apply Rate XOM separately at each **point of interconnection**.

(2) A **market participant** must achieve curtailment of its export opportunity merchant service within the response time specified in subsection 3(1) above in response to a **directive** from the **ISO**.

(3) The **market participant** may contract for export opportunity merchant service for a term within the minimum and maximum terms in the following table.

Rate	Minimum Term	Maximum Term
XOM	1 hour	1 **month**

(4) The terms and conditions of the **ISO tariff** form part of this rate.

Revision History

Effective	Description
2017-xx-01	Updated rate levels applied for as part of 2017 Tariff Update Application
2016-04-01	Updated charges, as approved in **Commission** Decision 21302-D01-2016 issued on March 31, 2016
2016-01-01	Updated charges, as approved in **Commission** Decision 20753-D02-2015 issued on December 21, 2015
2015-07-01	Updated subsections and charges, as approved in **Commission** Decision 3473-D01-2015 issued on June 17, 2015.
2013-10-01	Introduced for export service over Alberta-Montana **intertie**, as approved on interim refundable basis in **Commission** Decision 2013-325 issued on August 28, 2013.

Applicability

1(1) Rate PSC applies to **system access service** provided at a **point of delivery** to a **market participant** who receives **system access service** under Rate DTS, *Demand Transmission Service*, and:

(a) does not utilize transformation facilities owned by a **legal owner** of **transmission facilities** to step transmission voltage down to 25 kV or less; or

(b) is served through an unconventional connection such as one using metering transformers.

(2) Rate PSC does not apply to **system access service** to an isolated community as defined under the *Isolated Generating Units and Customer Choice Regulation*.

Rate

2(1) The **ISO** must determine the primary service credit to compensate a **market participant** whose connection does not include conventional transformation facilities owned by a **legal owner** of **transmission facilities**, including a connection for a **market participant** who has purchased, owns and operates its transformer.

(2) The **ISO** must determine the primary service credit as the sum of the products calculated by multiplying the volume and credit in each row (a) through (e) of the following table.

Volume in **Settlement Period**	Credit
(a) **Substation fraction**	$~~6,797.00~~6,943.00/**month**
(b) First (7.5 × **substation fraction**) MW of **billing capacity**	$~~2,752.00~~2,812.00/MW/**month**
(c) Next (9.5 × **substation fraction**) MW of **billing capacity**	$~~1,724.00~~1,761.00/MW/**month**
(d) Next (23 × **substation fraction**) MW of **billing capacity**	$~~1,202.00~~1,228.00/MW/**month**
(e) All remaining MW of **billing capacity**	$~~986.00~~1,007.00/MW/**month**

Terms

3(1) The **ISO** must apply Rate PSC separately at each **point of delivery**, except where Rate PSC applies to totalized **points of delivery** under subsection 5 of section 13 of the **ISO tariff**.

(2) The **ISO** must provide the primary service credit in conjunction with a reduced maximum local investment in accordance with subsection 8 of section 8 of the **ISO tariff.**

(3) The terms and conditions of the **ISO tariff** form part of this rate.

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Revision History

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2016-04-01	Updated charges, as approved in **Commission** Decision 21302-D01-2016 issued on March 31, 2016
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2015-07-01	Updated subsections and charges, as approved in **Commission** Decision 3473-D01-2015 issued on June 17, 2015.
2013-10-01	Updated credit levels in table in subsection 2(2), as approved on an interim refundable basis in **Commission** Decision 2013-325 issued on August 28, 2013 and on a final basis in **Commission** Decision 2014-242 issued on August 21, 2014.
2011-07-01	Revised and reformatted all subsections, as approved in **Commission** Decision 2011-275 issued on June 24, 2011.

Applicability

1(1) Rate STS applies to **system access service** provided at a **point of supply** to:

(a) the **legal owner** of a **generating unit** a **generating unit** or an **aggregated generating facility** that is not subject to a **power purchase arrangement**;

(b) the holder of the **power purchase arrangement** for a **generating unit** that is subject to a **power purchase arrangement**;

(c) the **legal owner** of an industrial system that has been designated as such by the **Commission**;

(d) the **legal owner** of an **electric distribution system** where a **generating unit** or an **aggregated generating facility** connected to the **electric distribution system** results in electricity flowing into the **transmission system**; or

(e) the City of Medicine Hat.

(2) Rate STS does not apply to a **generating unit** constructed under the *Small Power Research and Development Act*, to the extent the volume of energy sales from such a **generating unit** is conducted under a contract specifically executed pursuant to the provisions of the *Small Power Research and Development Act*.

Rate

2(1) The **ISO** must determine the charge under Rate STS in a **settlement period** as the losses charge calculated as the sum, over all hours in the **settlement period**, of **metered energy** in the hour multiplied by **pool price** multiplied by a **loss factor** for the facility, where the **loss factor** is determined in accordance with section 501.10 of the **ISO rules**, *Transmission Loss Factor Methodology and Requirements*, and is available to **market participants** in the **loss factors** section of the AESO website.

(2) The **ISO** must measure **metered energy** on a 15-minute interval for the purpose of calculating the losses charge under subsection 2(1) above.

Regulated Generating Unit Connection Cost

3 The **ISO** must apply an additional charge of $~~122.00~~95.00/MW per **month** for each regulated **generating unit** MW only to the regulated **generating units** identified in Appendix A of the **ISO tariff** and only to the end of the base life year of the regulated **generating units** as provided in that Appendix.

Terms

4(1) The **ISO** must apply Rate STS separately at each **point of supply**, except where Rate STS applies to totalized **points of supply** under subsection 5 of section 13 of the **ISO tariff**.

(2) The **ISO** must apply Rider E, *Losses Calibration Factor Rider*, to **system access service** provided under this rate.

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(3) The **ISO** must apply Rider J, *Wind Forecasting Service Cost Recovery Rider*, to **system access service** provided under this rate for a wind-powered **generating unit** or **aggregated generating facility**.

(4) The terms and conditions of the **ISO tariff** form part of this rate.

Revision History

Effective	Description
2017-xx-01	Updated rate levels applied for as part of 2017 Tariff Update Application
2016-04-01	Updated charges, as approved in **Commission** Decision 21302-D01-2016 issued on March 31, 2016
2016-01-01	Updated charges, as approved in **Commission** Decision 20753-D02-2015 issued on December 21, 2015
2015-07-01	Updated subsections and charges, as approved in **Commission** Decision 3473-D01-2015 issued on June 17, 2015 except for the losses charge component in subsection 2(1) approved on an interim basis in **Commission** Decision 2014-242 issued on August 21, 2014.
2013-10-01	Updated charges, as approved on an interim refundable basis in **Commission** Decision 2013-325 issued on August 28, 2014 and on a final basis, in **Commission** Decision 2014-242 issued on August 21, 2014 except for the losses charge component in subsection 2(1) approved on an interim basis in **Commission** Decision 2014-242 issued on August 21, 2014.
2011-07-01	Revised and reformatted all subsections, as approved in **Commission** Decision 2011-275 issued on June 24, 2011.

Applicability

1 Rider J applies to **system access service** provided under Rate STS, *Supply Transmission Service*, for a wind-powered **generating unit** or **aggregated generating facility.**

Rider

2(1) The **ISO** must determine the Rider J amount to recover the costs paid by the **ISO** for provision of a wind forecasting service for wind-powered **generating units** and **aggregated generating facilities** in Alberta.

(2) The **ISO** must calculate the Rider J charge as the product of **metered energy** in the **settlement period** multiplied by $0.05/MWh.

(4) The **ISO** must:

(a) review Rider J costs and revenues at the end of each calendar year; and

(b) adjust the Rider J amount in future years to address variances from forecasts of costs and revenues.

Terms

3(1) The **ISO** must apply Rider J separately at each **point of supply**.

(2) The terms and conditions of the **ISO tariff** form part of this rider.

Revision History

Effective	Description
2017-xx-01	Updated rider levels applied for as part of 2017 Tariff Update Application
2016-04-01	Updated charges, as approved in **Commission** Decision 21302-D01-2016 issued on March 31, 2016
2016-01-01	Updated to $0.06/MWh charge, as approved in **Commission** Decision 20753-D02-2015 issued on December 21, 2015.
2015-07-01	Updated to $0.12/MWh charge, as approved on an interim refundable basis in **Commission** Decision 2014-330 issued on December 3, 2014 and on a final basis in **Commission** Decision 3473-D01-2015 issued on June 17, 2015.
2011-07-01	Revised and reformatted all subsections, as approved in **Commission** Decision 2011-275 issued on June 24, 2011.

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Applicability

1 This section applies to a **market participant** who has requested or is receiving **system access service** under:

(a) Rate DTS, *Demand Transmission Service*;

(b) Rate PSC, *Primary Service Credit*; or

(c) Rate STS, *Supply Transmission Service*.

Connection Costs

2 The **ISO** must determine the costs of a connection project for a **market participant** to be those costs reasonably associated with facilities that:

(a) a **legal owner** of a **transmission facility** owns and operates;

(b) are required in order to:
- (i) provide **system access service** to a new **point of delivery** or **point of supply**; or
- (ii) increase the capacity of or improve **system access service** to an existing **point of delivery** or **point of supply**; and

(c) are reasonably required to meet the **market participant**'s:
- (i) **demand** and supply forecast; and
- (ii) **reliability** and operating requirements.

Classification of Participant-Related and System-Related Costs

3(1) All costs of a connection project will be classified as either participant-related or system-related.

(2) Participant-related costs will be those costs related to a contiguous connection project including costs associated with:

(a) the connection substation for the **point of delivery** or **point of supply**, including in out line configurations, where required;

(b) new radial transmission lines, including double-radial configurations, with only one (1) transmission source from the **transmission system** to the connection substation;

(c) a share of existing **transmission facilities** that were constructed to connect another **market participant**, where the existing facilities originally began **commercial operation** within the past twenty (20) years and where the share is determined in accordance with subsection 3 of section 9 of the **ISO tariff**;

(d) line moves or burials of existing transmission line;

(e) communication at the **point of delivery** or **point of supply**;

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(f) communication enhancements required at the nearest substation with communications equipment to allow direct communication between it and the connection substation;

(g) breakers and associated equipment required for the connection of the new radial transmission line to an existing substation;

(h) salvage labour required to remove existing **transmission facilities** to allow the installation of new or replacement facilities for a connection project, except where the cost of the removed facilities is treated as a capital maintenance cost by the **owner** of the **transmission facility**;

(i) changes to protection systems, equipment or settings related to the addition of a **generating unit** on an **electric distribution system** served through the connection substation;

(j) a **remedial action scheme**, if required;

(k) a phasor measurement unit, if required;

(l) the advancement of **transmission facilities** included as part of a critical transmission development or regional **transmission system** project under subsection 3(3)(b) below, calculated as the difference between the present values of the capital costs of the advanced and the as-planned facilities using the discount rate provided in subsection 11 below;

(m) facilities previously classified as system-related under subsection 3(3)(c) below and now reclassified as participant-related to meet the requirements of the connection project; and

(n) other facilities required to complete the **market participant**'s connection, including **transmission facilities** required to enable the **market participant** to meet all relevant technical requirements for the connection project.

(3) System-related costs will be those costs related to a connection project including non contiguous components of the project and any costs associated with:

(a) looped **transmission facilities**, which are facilities that increase the number of electrical paths between any two (2) substations, excluding the substation serving the **market participant** and which exclude any new radial transmission line;

(b) radial **transmission facilities** which, within five (5) years of **commercial operation**, are planned to become looped as part of a critical transmission development or regional **transmission system** project:

(i) in the **ISO**'s most recent long-term **transmission system** plan;

(ii) in a **needs identification document** filed with the **Commission**; or

(iii) as the **ISO** reasonably expects will be required in the future;

and

(c) **transmission facilities** in excess of the minimum size required to serve the **market participant** where, in the opinion of the **ISO**, economics or system planning support the development of such facilities.

Facilities in Excess of Good Electric Industry Practice

4 A **market participant** must pay, as part of the **construction contribution**, any participant-related costs of facilities which the **ISO** deems, in its opinion, to be in excess of those required by **good electric industry practice**.

Valuation of Facilities for Contribution Determination

5(1) The **ISO** must generally determine connection project costs based on the replacement costs new value of equipment, which is the current cost of similar new equipment having the nearest equivalent capability to the equipment being valued.

(2) The **ISO** must, when a connection project involves the installation of a transformer that replaces a smaller transformer which was removed from service at a substation, determine connection project costs by:

(a) reducing the participant-related costs for the connection project by the replacement cost new of the removed transformer when the **legal owner** of the **transmission facility** either:

(i) deems the transformer which is removed to be re-deployable for use at another substation or suitable for use as an operating spare; or

(ii) treats the cost of the transformer which is removed as a capital maintenance cost;

or

(b) not reducing the participant-related costs in any other circumstances including when the **legal owner** of the **transmission facility** scraps the transformer which is removed without treating its cost as a capital maintenance cost.

Allocation of Costs to Market Participants

6(1) The **ISO** must allocate to the **market participant** at the substation at which **system access service** is provided the balance of participant-related costs remaining after:

(a) the exclusion of costs, if any, under subsection 4 above reflecting facilities in excess of those required by **good electric industry practice**; and

(b) the reduction of costs, if any, under subsection 5 above reflecting replacement of a transformer removed from service.

(2) The **ISO** must allocate the participant-related costs determined in subsection 6(1) above among **market participants** receiving **system access service** at a single substation, which services may be solely under Rate DTS, solely under Rate STS or under a combination of both.

(3) The **ISO** must allocate the participant-related costs referred to in subsections 6(1) and 6(2) above to each **market participant** by multiplying those costs by the average **substation fraction** for the **market participant** determined in accordance with subsection 3(3) of section 9 of the **ISO tariff**, *Changes to System Access Service After Energization*.

(4) The **ISO** must deem costs allocated to a **market participant** taking service under Rate DTS to be **demand**-related costs.

(5) The **ISO** must deem costs allocated to a **market participant** taking service under Rate STS to be supply-related costs.

Determination of Construction Contribution

7(1) The **ISO** must calculate the **construction contribution** in accordance with the **construction contribution** provisions of the **ISO tariff** in effect on the date on which the **Commission** issues permit and licence for the connection project.

(2) A **market participant** must pay **construction contribution** amounts to the **legal owner** of the **transmission facility** in accordance with the **financial obligation** provisions of section 5 of the **ISO tariff**, *Financial Obligations for Connection Projects*.

(3) The **ISO** must calculate the **construction contribution**:

(a) for a **market participant** receiving service under Rate DTS, as the **demand**-related costs less the local investment determined under subsection 8 below.

(b) for a **market participant** receiving service under Rate STS, as the supply-related costs.

(4) A **market participant** receiving service under Rate STS must also pay the **ISO** any **legal owner**'s contribution for a **generating unit** or an **aggregated generating facility** required under section 10 of the **ISO tariff**, *Generating Unit Owner's Contribution*.

Determination of Local Investment

8(1) The **ISO** must calculate the maximal local investment:

(a) based on the **contract capacity** and investment term set out in the **system access service** agreement for a connection project for a **market participant** taking service under Rate DTS or under Rate DTS with Rate PSC;

(b) excluding any **contract capacity** transferred from another **point of delivery**; and

(c) using an investment term from five (5) to twenty (20) years inclusive, commencing on the date of **commercial operation**.

(2) The **ISO** must calculate the maximum local investment for a connection project for a new **point of delivery** as the sum of annual amounts for each year in the investment term by adding the products of the values from each of rows (c) through (g) of the table below, where the product for a row is calculated by multiplying:

(a) the **substation fraction** or **contract capacity**, as applicable, from column A; and

(b) the investment amounts from column B or column C, as applicable.

Column A	Column B	Column C
Tier	Investment for Service Under Rate DTS	Investment for Service Under Rate DTS with Rate PSC
(c) **Substation fraction** (for new **points of delivery** only)	$~~78 350~~80 150/year	$~~16 450~~16 830/year
(d) First (7.5 × **substation fraction**) MW of **contract capacity**	$~~31 750~~32 450/MW/year	$~~6 670~~6 810/MW/year
(e) Next (9.5 × **substation fraction**) MW of **contract capacity**	$~~19 900~~20 350/MW/year	$~~4 180~~4 270/MW/year
(f) Next (23 × **substation fraction**) MW of **contract capacity**	$~~13 850~~14 200/MW/year	$~~2 910~~2 980/MW/year

Column A	Column B	Column C
(g) All remaining MW of **contract capacity**	$~~8 950~~9 150/MW/year	$0/MW/year

(3) The **ISO** must calculate the maximum local investment for a connection project that accommodates a **contract capacity** increase at an existing **point of delivery** using:

(a) the **contract capacity** representing the incremental **contract capacity** since the most recent change in **construction contribution** at the **point of delivery**;

(b) the **substation fraction** based on **contract capacities** after the increase;

(c) the existing **contract capacity** to establish the initial tier in which investment becomes available for the incremental **contract capacity**; and

(d) investment available from subsequent tiers, as appropriate, where the sum of existing and incremental **contract capacities** exceeds the remaining MW in the initial tier.

(4) The **ISO** must calculate the maximum local investment for a connection project that includes increases or decreases to **contract capacity** over the investment term as the sum of the investment for each incremental amount of **contract capacity**, to be:

(a) calculated in accordance with subsections 8(2) and 8(3) above, based on each increment of **contract capacity** and the years for which each increment is contracted, and

(b) discounted from the beginning of the first **month** in which the increment of **contract capacity** exists back to the date of **commercial operation** of the connection project, using the discount rate provided in subsection 11 below.

(5) The **ISO** must determine the maximum local investment as the lesser of:

(a) the amount calculated in subsection 8(2), 8(3) or 8(4) above; or

(b) the **demand**-related costs.

Operations and Maintenance

9(1) A **market participant** taking service under Rate DTS must pay, as part of the **construction contribution**, an operations and maintenance charge to be added to any participant-related costs of facilities which are deemed to be in excess of those required by **good electric industry practice** in subsection 4 above.

(2) The **market participant** must estimate and the **ISO** must agree to the operations and maintenance charge calculated:

(a) as the present value of the full incremental maintenance cost, incremental operations cost, and overheads associated with the operations and maintenance of the facilities which are deemed to be in excess of those required by **good electric industry practice**,

(b) over the useful life of those facilities or twenty (20) years, whichever is less.

(3) The **market participant** must use the discount rate provided in subsection 11 below in the present value calculation.

Limitations

10 The **ISO** may exercise discretion in the application of the **construction contribution** provisions in the **ISO tariff**, including the determination of costs to be system-related in certain circumstances that might, under strict application of the **construction contribution** provisions, have been classified as participant-related.

Discount Rate

11(1) The **ISO** must determine the discount rate applicable to the calculation of **construction contributions** under this section 8 of the **ISO tariff** and payments in lieu of notice under section 9 of the **ISO tariff** as:

$$\text{discount rate} = \left[(1-\text{E}) \times (\text{YLD} + 1\%)\right] + \left(\frac{\text{E} \times \text{ROE}}{1-\text{T}}\right)$$

where:

(a) E is equal to the **Commission**-approved equity ratio applicable to the **legal owner** of **transmission facilities**, as amended from time to time;

(b) YLD is equal to the yield on 30-year Government of Canada bonds;

(c) ROE is equal to the **Commission**-approved rate of return on equity applicable to the **legal owner** of the **transmission facilities**, as amended from time to time; and

(d) T is equal to the combined federal and provincial income tax rate applicable to the **legal owner** of the **transmission facilities**.

(2) The **ISO** must use zero (0) as the tax rate T in subsection 11(1) above for a **legal owner** of **transmission facilities** that does not pay income tax, including a non-income tax paying municipal **legal owner** of **transmission facilities**.

Miscellaneous

12(1) The **ISO** must make reasonable efforts to ensure that, where **transmission facilities** must be relocated, the party causing the relocation pays all reasonable costs associated with the relocation.

(2) The **ISO** must, where new facilities between adjacent **balancing authority areas** are required, allocate the costs of such facilities to the **ISO** and to the party responsible for costs in the other **balancing authority area** based on the extent to which each benefits directly from the facilities.

Revision History

Effective	Description
2017-xx-01	Updated investment levels applied for as part of 2017 Tariff Update Application
2016-04-01	Updated charges, as approved in **Commission** Decision 21302-D01-2016 issued on March 31, 2016
2016-01-01	Updated charges, as approved in **Commission** Decision 20753-D02-2015 issued on December 21, 2015
2015-07-01	Updated charges, as approved in **Commission** Decision 3473-D01-2015 issued on June 17, 2015 except for subsection 3 which remains as approved in **Commission**

	Decision 2011-275 issued on June 24, 2011
2013-10-01	Updated charges, as approved on an interim refundable basis in **Commission** Decision 2013-325 issued on August 28, 2013 and on a final basis in **Commission** Decision 2014-242 issued on August 21, 2014 except for subsection 3 which remains as approved in **Commission** Decision 2011-275 issued on June 24, 2011.
2011-07-01	Revised and reformatted all subsections, as approved in **Commission** Decision 2011-275 issued on June 24, 2011.