




## AESO 2007 Tariff Consultation


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Regulatory, AESO  
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AESO Stakeholder Meeting, Calgary



## Agenda

- Introduction
  - Heidi Kirrmaier, Vice President, Regulatory, AESO
- AESO 2007 rates proposals
  - John Martin, Manager, Regulatory, AESO
  - Lunch (on your own)*
  - Rates presentation may continue after lunch
- AESO 2007 terms and conditions proposals
  - Ed Hucman, Manager, Regulatory, AESO
  - Conclude at 3:30 PM*
  - May continue to 4:30 PM if discussion warrants

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## Basis for Presentation

- Current draft of 2007 tariff application as distributed on September 18, 2006
  - Forecast 2007 revenue requirement
  - Forecast 2007 billing determinants
- Focuses on significant changes to tariff since June 29, 2006 presentation
  - Includes discussion of comments received from stakeholders in meetings and written submissions
- Presentation will be posted on AESO website
  - Written stakeholder comments also posted on website


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## 2007 Tariff Consultation

- Consultation began in December 2005
- Studies, papers, and comment processes led to presentation of tariff proposal on June 29, 2006
- Further revisions to tariff proposal distributed on July 21, 2006
- Consultation extended to allow additional discussion and meetings with stakeholders
- Revised tariff proposal distributed on September 18, 2006
- AESO to file 2007 tariff application in late October


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### Cost Causation Activities Since July 4 Draft

- Finalized bulk line data (79 lines at 240 kV)
- Added 2004 hourly data to analysis of bulk line load coincidence with system load
  - In additional to 2005 hourly data already analyzed
- Utilized substation fractions for functionalization of dual-use substations to reflect EUB Decision
- AESO has contracted National Economics Research Associates (NERA) of Los Angeles to review methodology and conclusions of bulk system analysis
  - Review expected to be completed in early October

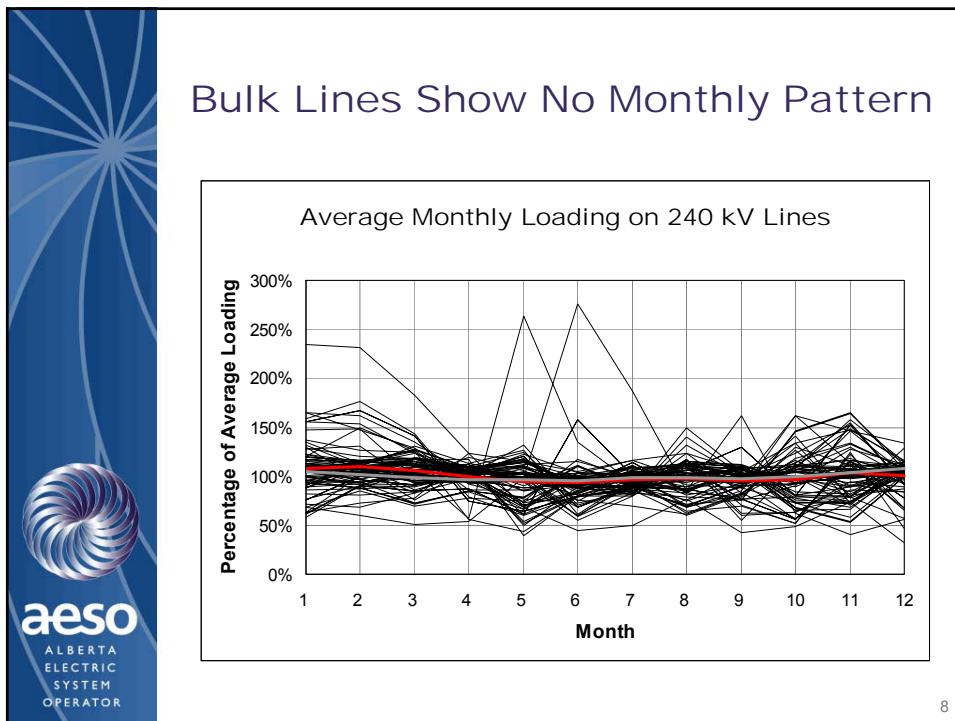
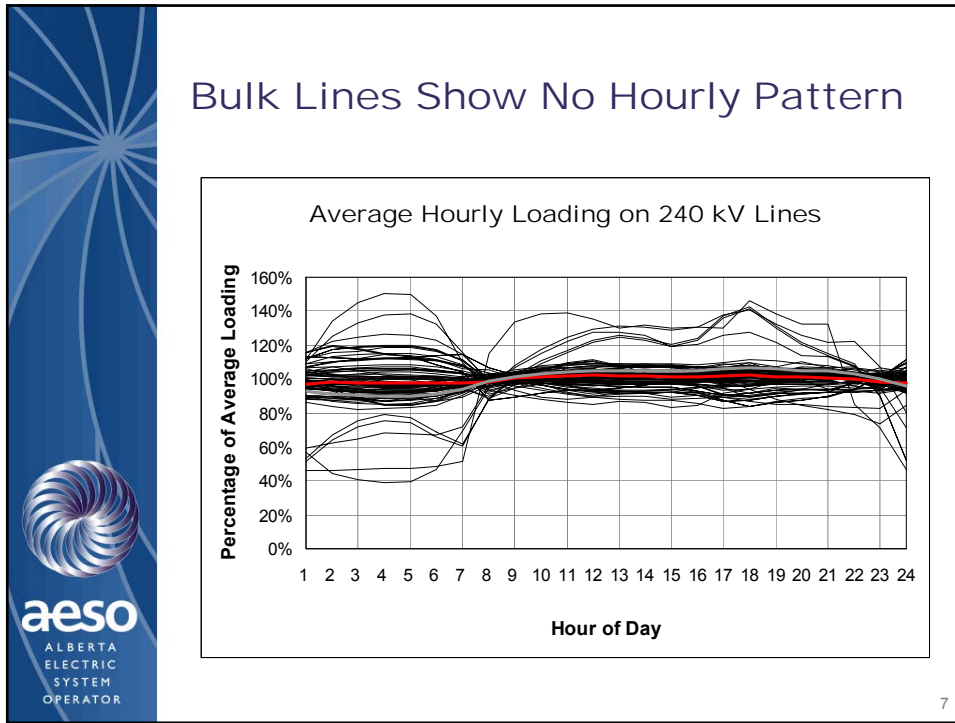
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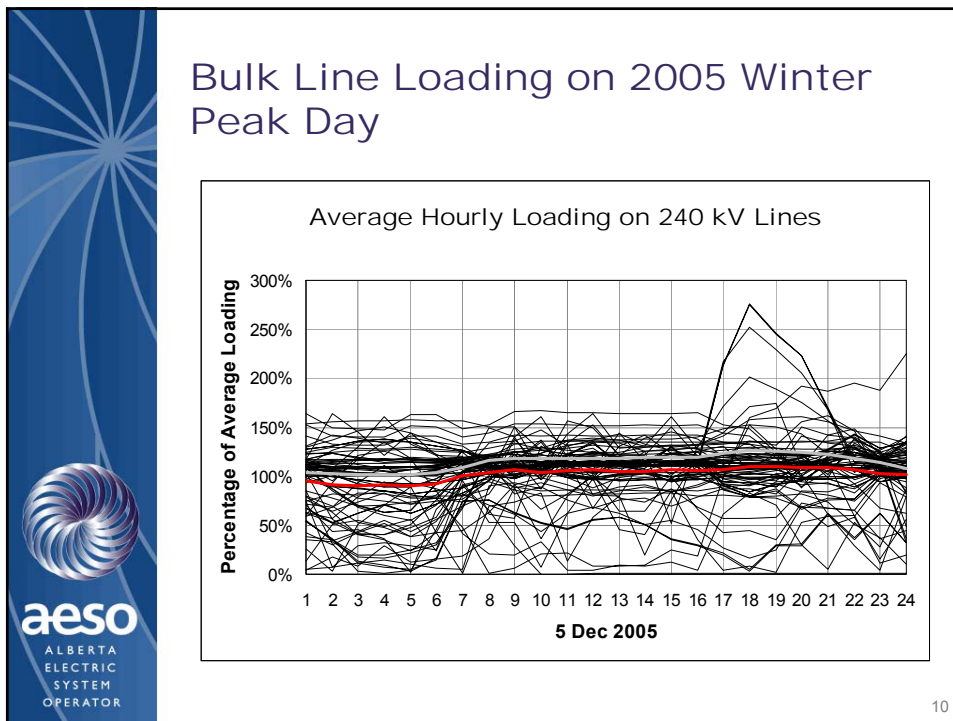
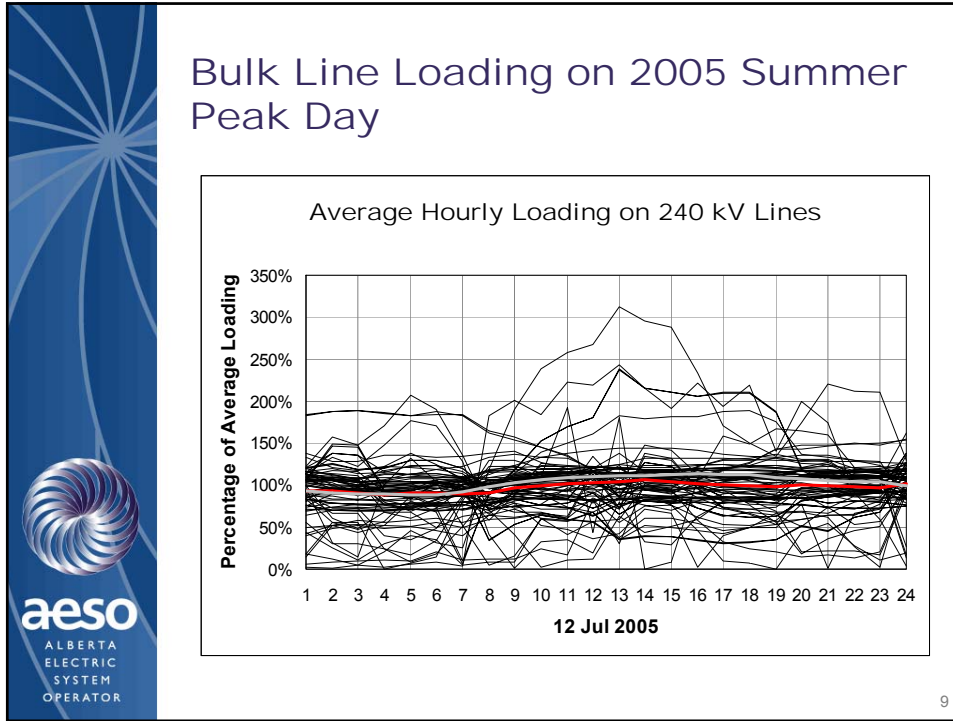



### Bulk Line Load Coincidence With System Load

	Correlation Coefficient	
	2004	2005
<b>Line Loading</b>		
• Simple Average (Unweighted)	0.07	0.12
• <b>Weighted by Line Length</b>	<b>0.01</b>	<b>0.08</b>
• Weighted by Line NBV	0.11	0.18
<b>Percentage of Thermal Capacity</b>		
• Simple Average (Unweighted)	0.00	0.00
• Weighted by Line Length	-0.04	-0.03
• Weighted by Line NBV	0.04	0.04

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## Why Billing Capacity?

- Bulk system is designed primarily to satisfy demand-related criteria on each bulk system component
  - Thermal capacity, voltage, and stability
- Load in every hour is important
  - In every hour, some bulk lines are heavily loaded
- Average bulk system loading is very flat
  - 97% to 103% of average on an hourly basis
- Non-coincident peak demand (NCP) with ratchet captures importance of peak in every hour
  - Maintains success of pre-2006 billing determinant

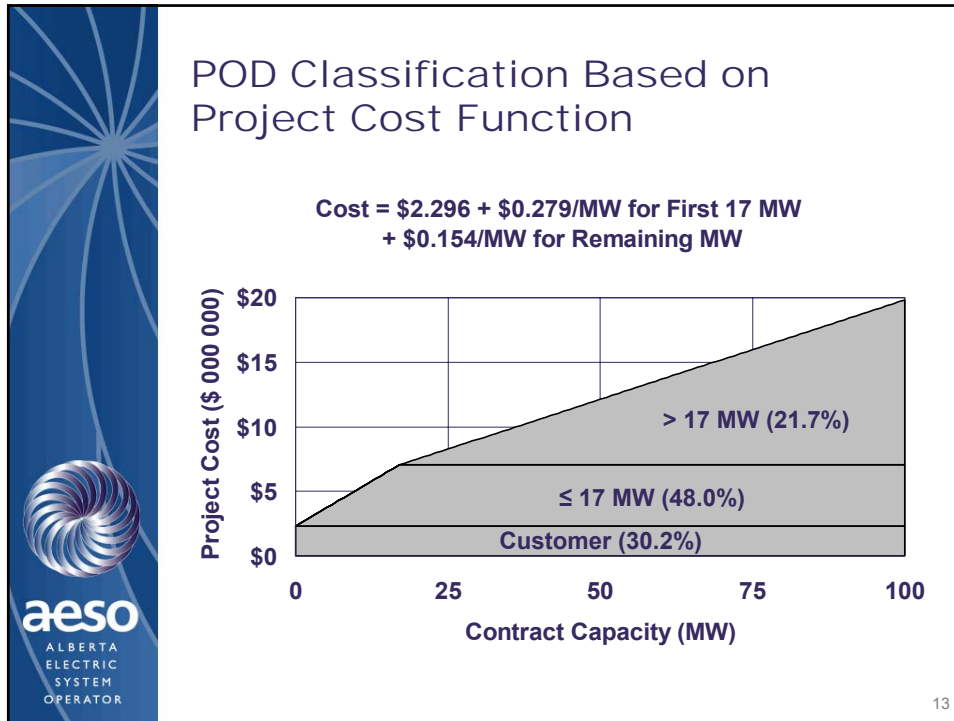
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## Moderation of Bulk System Demand Classification

- POD peaks are not coincident with every bulk system component peak
- Demand-related classification reduced to reflect diversity of POD peaks
  - Based on average percentage of peak AIL at time of annual maximum loading on each bulk line
  - May refine by using DTS hourly loads and monthly bulk line peaks
- Demand classification reduced to 80.9% of unmoderated value

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### Final Functionalization and Classification

- 2007 cost functionalization and classification:

Function	Total	Classification			
		CP	NCP	Energy	Customer
Bulk	41.7%	–	22.2%	19.5%	–
Local	17.4%	–	14.3%	3.0%	–
POD	40.9%	–	28.6%	–	12.4%
Total	100.0%	–	65.1%	22.5%	12.4%

*Totals may be different due to rounding*

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## Functionalization and Classification for Rate Design

- Cost functionalization and classification used for rate design:

Function	Total	Classification			
		CP	NCP	Energy	Customer
System	59.1%	–	36.5%	22.5%	–
POD	40.9%	–	28.6%	–	12.4%
<b>Total</b>	<b>100.0%</b>	<b>–</b>	<b>65.1%</b>	<b>22.5%</b>	<b>12.4%</b>

*Totals may be different due to rounding*


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## DTS Interconnection Charge

- System Charge:
  - \$1,395.00/MW of Billing Capacity
  - \$1.87/MWh of Metered Energy
- Point of Delivery Charge:
  - \$1,364.00/MW for first 17 MW of Capacity
  - \$753.00/MW for remaining MW of Capacity
  - \$11,194.00/month × Substation Fraction
- Billing Capacity is highest of:
  - highest Metered Demand in Billing Period
  - 90% of highest Metered Demand in 24 months
  - 90% of Contract Capacity


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## Other DTS Charges

- Operating Reserve Charge:
  - Metered Energy × 3.70% × Pool Price
- Voltage Control Charge:
  - \$1.02/MWh of Metered Energy
- Other System Support Services Charge:
  - \$79.00/MW of highest Metered Demand
- Power Factor Deficiency Charge:
  - \$400.00/MVA where Power Factor < 90%
  - Clarification of wording
  - Reviewing treatment at PODs with distribution-connected generation


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## Point of Delivery Cost Analysis

- *Contribution Study* determined \$2.296 million customer cost based on minimum-intercept analysis
- Least cost estimates for DTS services of 5 MW or less prepared as part of 2005-2006 analysis of customer-owned substations showed similar customer cost of \$2.141 million
- Review of facilities data for small-capacity DTS loads show about two-thirds utilize transformers of 7.5 MVA and greater capacity
- *All based on conventional interconnections*

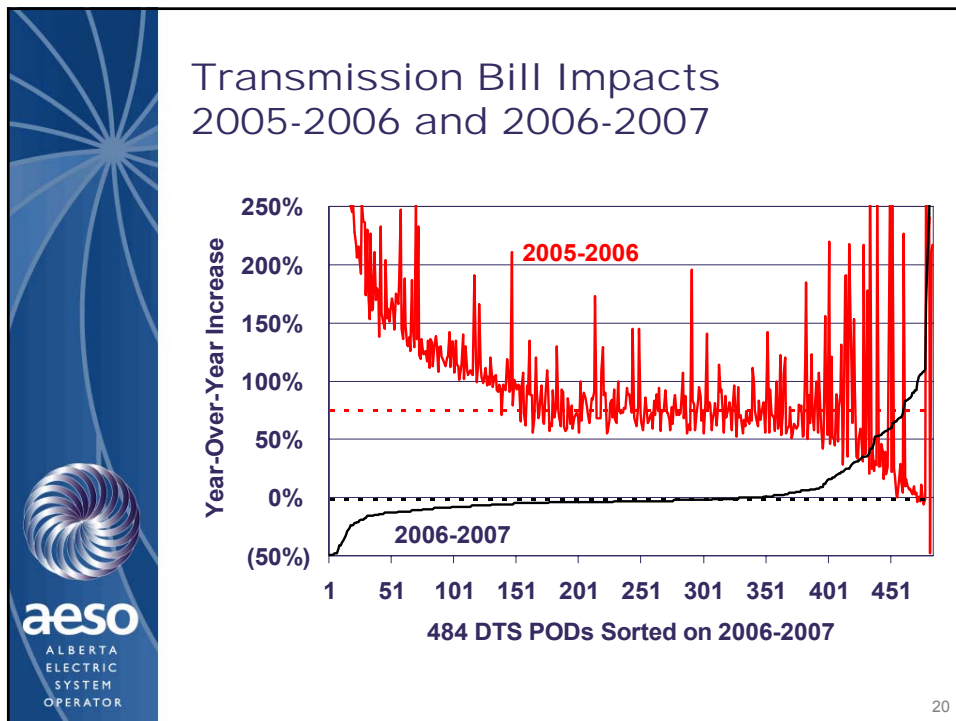
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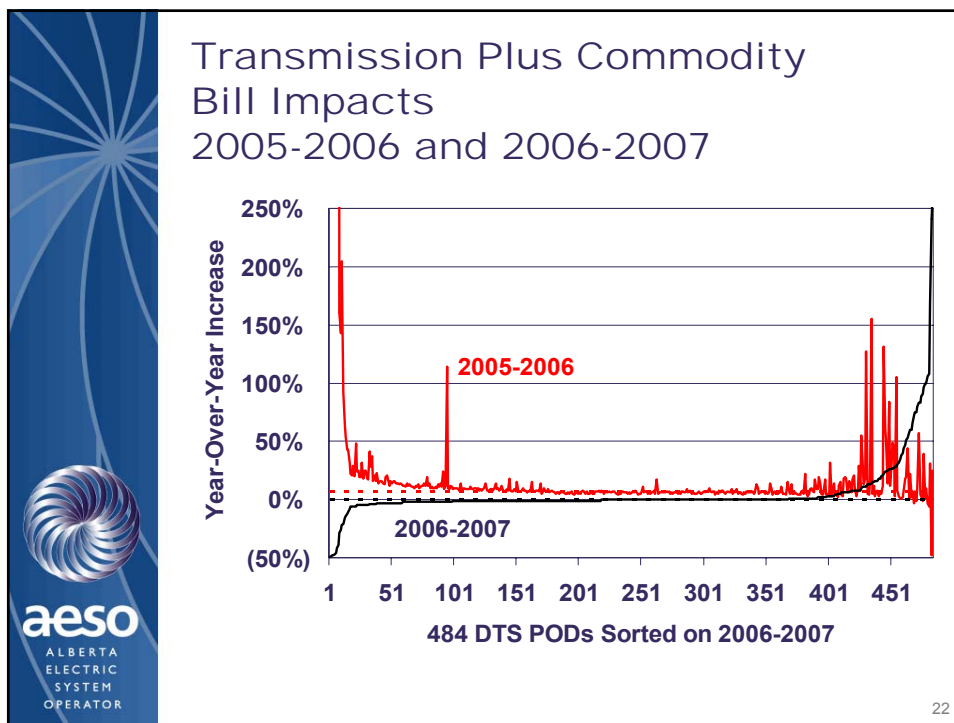
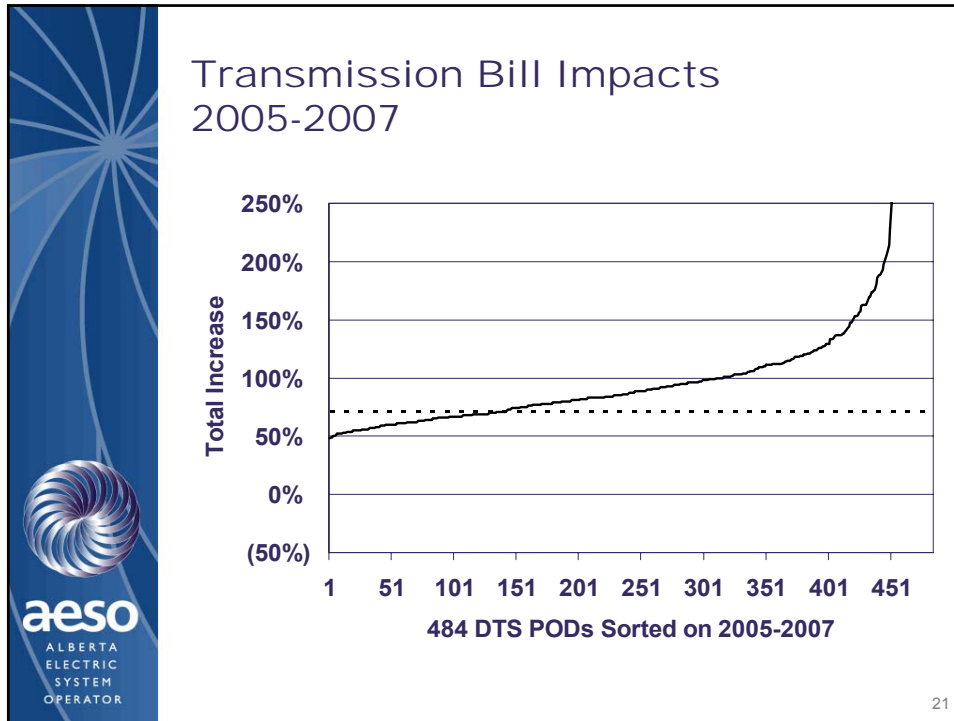


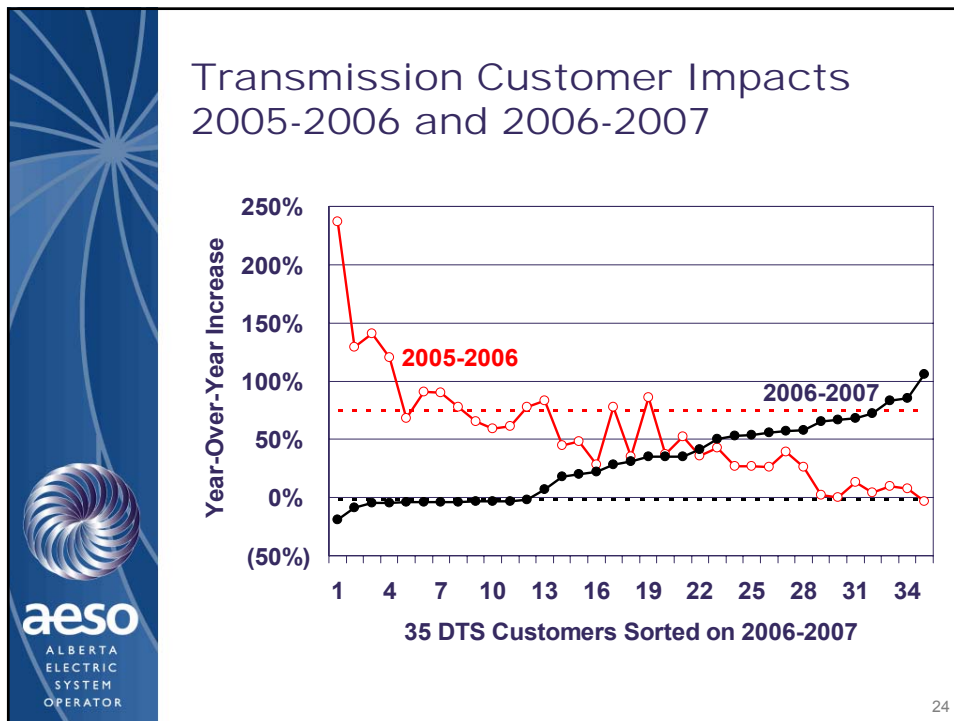
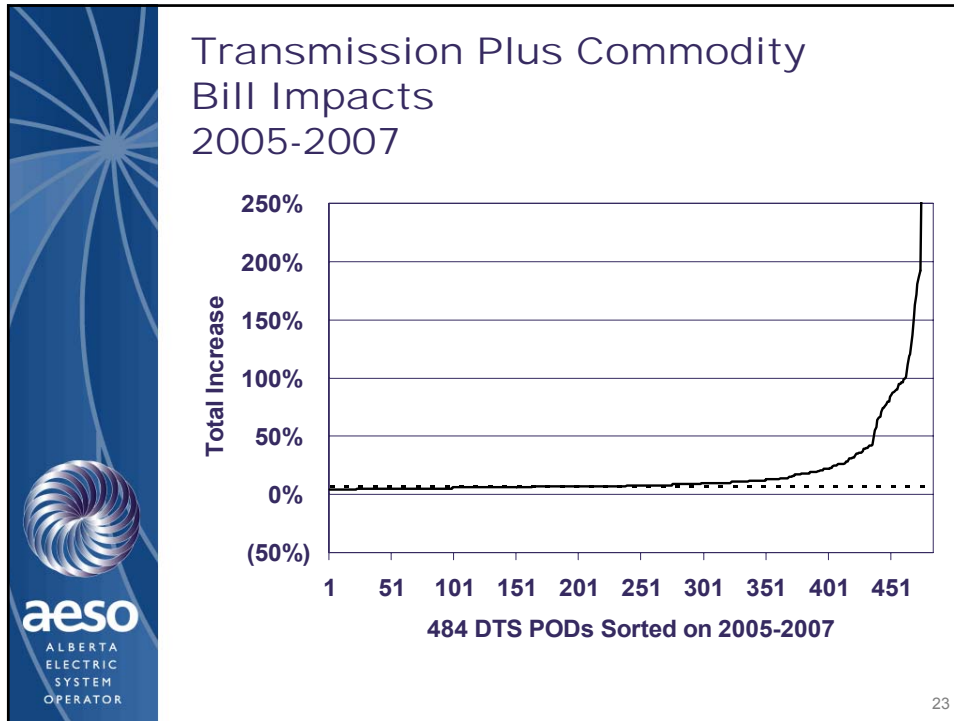
### Point of Delivery Cost Analysis (cont'd)

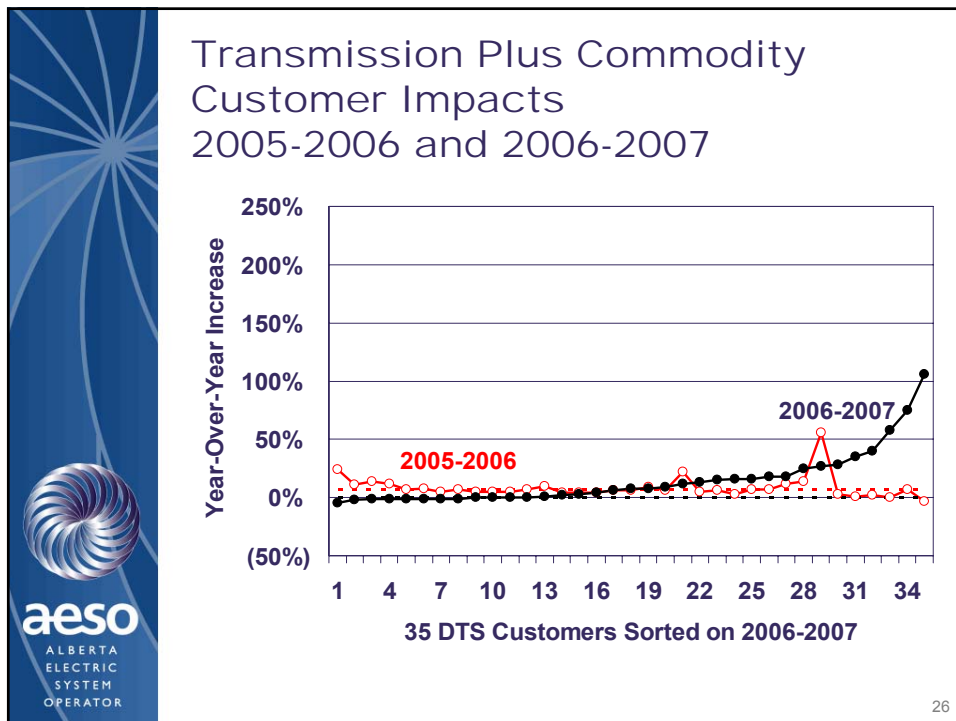
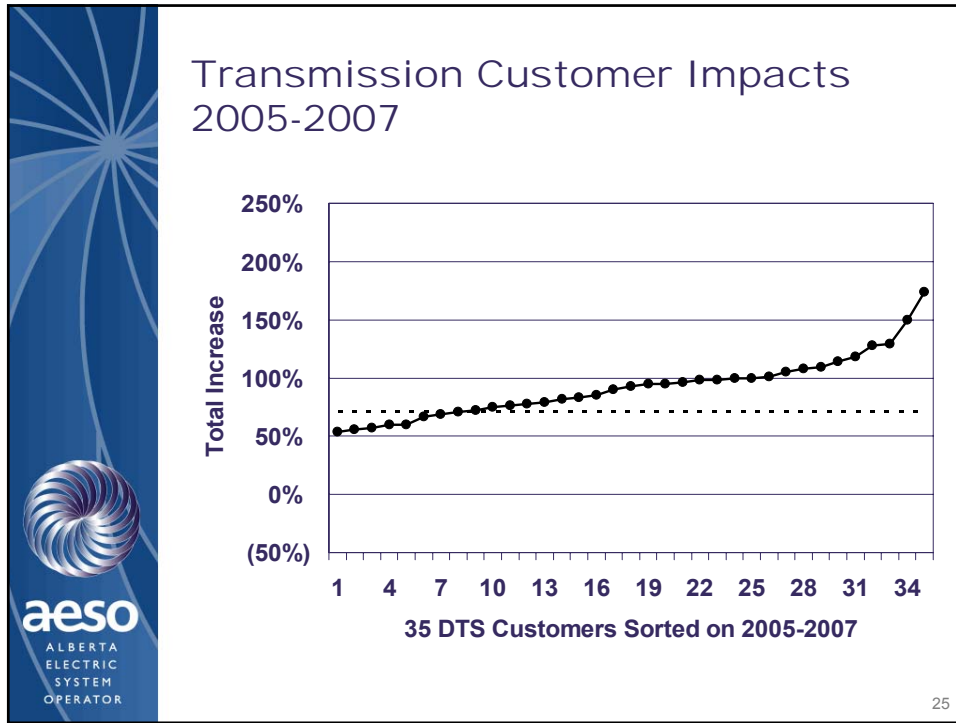
- Some DTS loads do not have conventional interconnections
  - Metering (PT) transformers and other unusual interconnections
  - “Virtual” interconnections at isolated communities
- AESO proposes that such loads be eligible for Primary Service Credit
  - Credit to be available at any DTS interconnection where the TFO does not own conventional transformation facilities
  - Maximum available investment will be correspondingly reduced

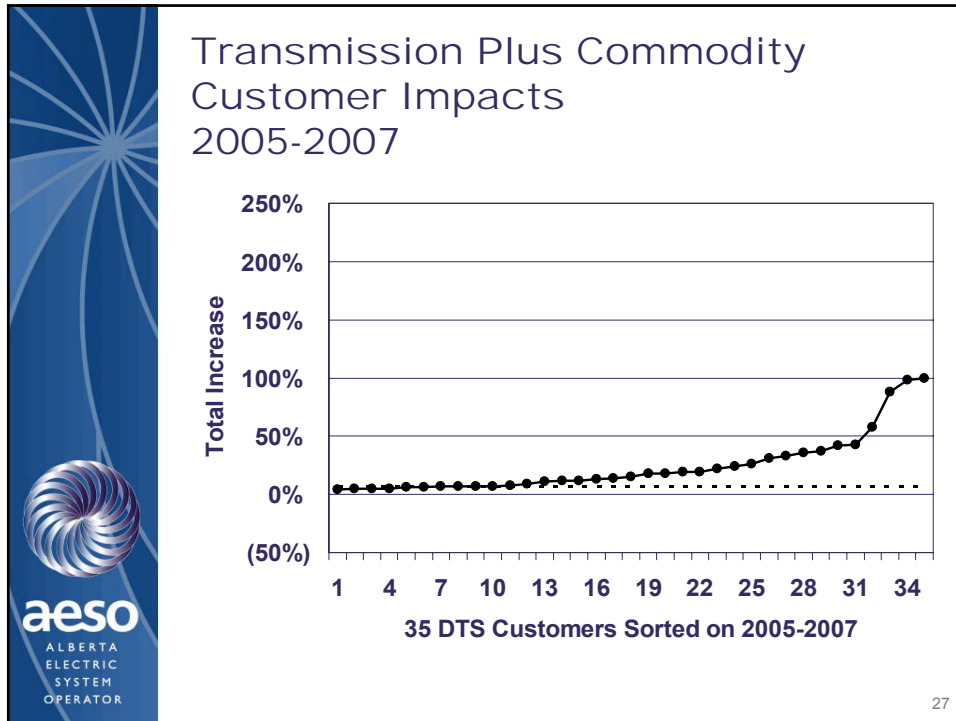
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- ### Bill Impact Observations
- 2006-2007 impacts based on actual billing data from June 2005 to May 2006
  - Average DTS bill impact is  $-1.64\%$  decrease
    - 319 accounts change between  $-10\%$  and  $+10\%$
    - 47 accounts see greater than  $+50\%$  increase
  - Average DTS plus commodity bill impact is  $-0.27\%$  decrease
    - 411 accounts change between  $-10\%$  and  $+10\%$
    - 22 accounts see greater than  $+50\%$  increase
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### Bill Impact Observations (cont'd)

- Bill impacts generally increase:
  - (a) as load factor decreases (due to NCP bulk system charge) and
  - (b) as billing capacity increases (due to conversion of some \$/month amounts to \$/MW amount in POD charge)
- On average, all accounts less than 25% load factor see an increase over all billing capacities
- All DISCOs see decreases in aggregate primarily due to POD charge change
  - Under current rate DISCO PODs pay \$21,899/month regardless of size; under proposed rate will pay \$11,194/month


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### Services for "Partial-Requirements Customers"

- *Supplemental service* for load in excess of onsite generation — generally provided under "full requirements" rate
- *Scheduled maintenance service* for generator planned outages — available under DOS Term with some restrictions
- *Economic replacement service* where costs are less expensive than onsite generation — available under DOS rates
- *Backup or standby service* for unscheduled outages of onsite generation — currently no specific provisions


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## Backup or Standby Service

- Backup or standby service can currently be accommodated under the DTS rate (up to capacity or other limits on system)
  - Paid for either through increased contract capacity (which is non-recallable) or through 2-year 90% ratchet on above-contract capacity (which is recallable)
- Issue is whether charge for backup or standby service is aligned with costs
  - Cost for 1 MW used for 1 hour per year: \$15,207
  - Cost for 1 MW used for 8,760 hours: \$33,121
  - Represents system component of interconnection charge only


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## Backup or Standby Service (cont'd)

- In response to customer consultation, AESO proposed in June a backup rate which would incur similar costs as DTS rate at 10% load factor
  - Cost for 1 MW used for 1 hour per year: ~\$0
- Potential exists for significant uptake
  - 50 PODs with 600 MW could switch to new rate
  - 50 PODs with 800 MW could take additional capacity
  - Many expected to be concentrated in areas where concurrent use may be a problem
- Possibility of unacceptably high risks for transmission system operations and reliability

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**Backup or Standby Service** (cont'd)


↓  
In general, as charges for backup or standby service decrease...

↑  
...utilization would be expected to increase...

↑  
...and risk of operations and reliability issues would increase

- Wires-related “hard” costs can be quantified but
- Risk-related “soft” costs are not quantifiable
- DTS rate may already strike a suitable balance


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**Backup or Standby Service** (cont'd)

- Main concern is with unscheduled nature of backup or standby service
- Less concern with scheduled maintenance service for generator planned outages
  - Eligible for DOS Term *only if customer would reduce load rather than incur increased ratchet levels under DTS rate*
  - Propose to remove this restriction on use of DOS Term for scheduled maintenance
- Further discussion expected in meeting with IPCAA members on September 27


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### DOS 7 Minutes

- Demand Opportunity Service rate should recover variable costs and provide a contribution to fixed costs
- Variable costs include variable components of interconnection system and operating reserves
- Contribution to fixed costs is 50% of fixed component of interconnection system
- All costs converted to \$/MWh: \$5.81/MWh
  - For DOS 7 Minutes
  - Minimum charge based on 75% of opportunity capacity


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### DOS 1 Hour — Terminated

- DOS rates are differentiated on curtailment provisions and qualifying criteria
- Curtailment provisions for all DOS rates are essentially the same
- Qualifying criteria are the same for DOS 7 Minutes and DOS 1 Hour
  - Additional criterion for DOS Term
- Propose to terminate DOS 1 Hour

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## DOS Term

- Propose to relax DOS Term qualifying criteria
- Propose to increase DOS Term contribution to fixed costs to be equivalent to “system” ratchet charges for load at 10% load factor
- All costs converted to \$/MWh: \$21.65/MWh
  - For DOS Term
  - Minimum charge based on 75% of opportunity capacity


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## Export and Import Services

- XTS: Non-recallable Export Transmission Service
- XOS 1 Hour: Hourly Export Opportunity Service
- XOS 1 Month: Monthly Export Opportunity Service
- Charges aligned with and based on DTS rate
- No changes to import service (IOS)
  - No equivalent non-recallable and opportunity distinctions for domestic supply service (STS)


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### XTS: Export Transmission Service

- XTS rate should recover both fixed and variable costs of DTS rate
  - Excludes POD charge
- Fixed component of interconnection system charge converted to \$/MWh
  - Minimum charge based on 90% of scheduled capacity in hours in which ATC is available
- Curtailment just prior to DTS loads
- Minimum contract term of 1 year
- Curtailment and scheduling provisions to be developed in OPPs


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### XTS Rate

- System Charge:
  - \$4.90/MWh of Energy Transfer
- Operating Reserve Charge:
  - Energy Transfer × 3.70% × Pool Price
- Voltage Control Charge:
  - \$1.02/MWh of Energy Transfer
- Other System Support Services Charge:
  - \$0.15/MWh of Energy Transfer


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### XOS 1 Hour Rate

- Same premise as DOS rate: recover variable costs and provide a contribution to fixed costs
  - Variable costs include variable components of interconnection system and operating reserves
  - Contribution to fixed costs is 50% of fixed component of interconnection system
- All costs converted to \$/MWh: \$5.81/MWh
  - For XOS 1 Hour
  - Minimum charge based on 75% of scheduled capacity
- Similar curtailment provisions to DOS: XOS curtailed first, but DOS curtailed more frequently for regional constraints


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### XOS 1 Month Rate

- XOS 1 Hour rate plus additional contribution to fixed costs
- All costs converted to \$/MWh: \$6.03/MWh
  - For XOS 1 Month
  - Minimum charge based on 75% of scheduled capacity


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### Merchant Export Services

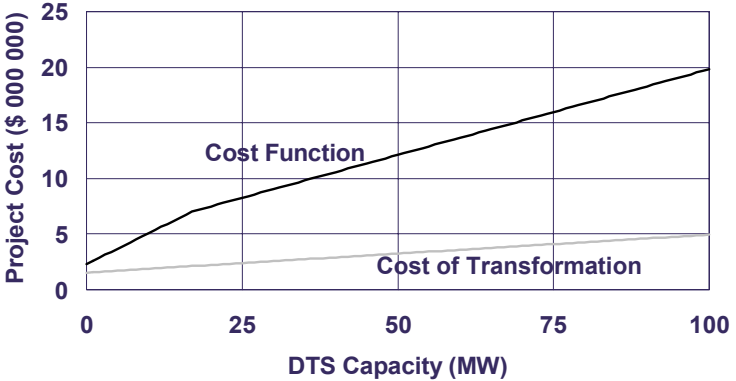
- Merchant rates same as export rates, reduced by amount attributable to existing inter-ties
- MTS System Charge: \$4.25/MWh
  - Reduced from XTS System Charge of \$4.90/MWh
  - Plus other components as in XTS rate
- MOS 1 Hour Rate: \$5.36/MWh
  - Reduced from XOS 1 Hour Rate of \$5.81/MWh
- MOS 1 Month Rate: \$5.55/MWh
  - Reduced from XOS 1 Month Rate of \$6.03/MWh
- No specific merchant import service

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### Primary Service Credit

#### PSC Derived From Project Cost Function



DTS Capacity (MW)	Cost Function (\$ 000 000)	Cost of Transformation (\$ 000 000)
0	2.5	1.0
25	8.0	2.0
50	12.5	3.0
75	16.0	4.0
100	20.0	5.0

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### Primary Service Credit (cont'd)

- Align credit with POD charge in DTS rate
  - Include application of substation fraction
- Primary Service Credit:
  - \$166.00/MW of Billing Capacity
  - \$7,522.00/month × Substation Fraction
- PSC is available at interconnections that do not require or do not otherwise include TFO-owned transformation
  - In conjunction with a reduced maximum investment level
- Level of credit still being assessed and subject to change

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### AESO Contacts

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