At the Alberta Electric System Operator (AESO), we’re responsible for operating Canada's first competitive, real-time wholesale electricity market, which has nearly 200 participants and about $5 billion in annual energy transactions. As an independent system operator, the AESO leads the safe, reliable and economic planning and operation of Alberta's interconnected transmission power system.

We're focused on: planning and implementing transmission projects to strengthen the provincial grid; maintaining reliability in a more challenging real-time operating environment; efficiently connecting customers to Alberta's power system; and ensuring that Alberta's competitive electricity markets are fair, efficient and openly competitive.

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On the cover:

Kim Langille
Stakeholder Relations/Communications
Pung Toy
Transmission
Don Olson
System Operations
Marina Jagbandhansingh
Legal

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Whether it’s reliable power, reliable markets or reliable people, you can count on the AESO to deliver. It’s our job to make sure Alberta’s electric system reliably delivers power when and where it’s needed.

Reliable Power

The power grid must meet the challenges of a growing provincial economy and increasing demands for reliable electricity for Alberta’s industry, business and residential consumers. The AESO ensures that Alberta’s interconnected power grid is reliable today and in the future.

Reliable Markets

The AESO’s efforts are aimed at ensuring the provincial wholesale power market is sustainable, predictable and adding long-term value. We play a key role in building confidence in Alberta’s competitive electricity markets to support ongoing investment in the power industry.

Reliable People

At the AESO we are committed to industry stakeholder consultation that builds trust and demonstrates professionalism and accountability. Our consultation is also intended to provide transparency and clarity about our plans and decisions. We strive to make fair and balanced decisions with respect for our public interest mandate.
Chair’s Message

Maury Parsons
AESO Board Chair

We have a strong and clear commitment to consultation with stakeholders that will deliver on key corporate objectives and positively affect the success of the entire industry.

In these pages last year I remarked on the AESO’s direction. The thrust for 2005 was to refocus on our core business, with a strong and clear commitment to consultation with stakeholders that would deliver on key corporate objectives and positively affect the success of the entire industry. I’m pleased to say that’s what happened. We made significant strides in achieving some core business objectives and in implementing respected and trusted processes to build industry confidence in the AESO’s ability to fulfill its mandate.

Under the direction of our senior executives, Dale McMaster, President and Chief Executive Officer and David Erickson, Senior Vice-President and Chief Financial Officer, the AESO has established a solid team of accomplished executives and created a strong foundation of achievements, and a strategic plan to build on. Our Board fully supports their efforts. In Dale’s message on the following pages you’ll read about the details of the AESO’s business results and forward planning.
From the very beginning we developed strong relationships with industry, government and regulators to provide valuable feedback as we evolved.

At this time, I’d like to reflect about our history and how it has brought us to where we are today.

During the last eight years that I’ve spent as Chair of the Power Pool Council and now the AESO Board, the depth of change and the continuing growth in accountability for our company has increased every year. Clearly this is testament to our success. We’ve continued to build the AESO into a centre of excellence through:

- talented people;
- strong working relationships with stakeholders and other agencies;
- solid corporate governance;
- clear strategic direction.

In the early days of our organization, we moved from a volunteer council composed of industry stakeholders to a Board of Directors with individuals independent from the electric industry and started to establish Canada’s first competitive market for electric energy. This was a period of significant development and growth as we built the technical and human capability to meet our new requirements.

From the very beginning we developed strong relationships with industry, government and regulators to provide valuable feedback as we evolved. There was no template to follow in those days. Our network of open and honest relationships for feedback was critical as we continued to learn and expand our knowledge while our role developed and the marketplace continued to evolve.

To govern effectively, our Board did not stand still. We have kept pace with constant change through constant growth — growth in our capacity to manage in uncertainty, to navigate effectively in an evolving environment and to maintain our focus. We have built a strong multidisciplinary Board with expertise in a broad range of areas, including the electricity, oil and gas businesses, energy management, governmental affairs, regulatory, finance, auditing, and technology.

The AESO’s ability to rise to the continuing challenges of new accountabilities in an evolving industry is the best indicator of the excellent skills and capabilities of the organization’s executive, management and employees.

Each year we’ve achieved success and we’ve attracted and retained top-notch talent that continues to deliver a level of unequalled excellence. I have every confidence that this executive team will continue building an organization where people will steadily improve their abilities to achieve more as the critical importance of the AESO’s role in the industry evolves and expands.
AESO Board Members

Standing left to right:
Dr. John Feick | Dr. Ron George | Murray Nelson | Harry Hobbs | Bill Burch |

Seated left to right:
Bob McKenzie | Nancy Laird | Maury Parsons |

To govern effectively, our Board did not stand still. We have kept pace with constant change through constant growth – growth in our capacity to manage in uncertainty, to navigate effectively in an evolving environment and to maintain our focus.
Effective May 31, 2006, I will retire and a new Chair will set the course for continued AESO achievement. We have a solid foundation and strong leadership to support the Board and new Chair during the next wave of change. The challenges of this complex industry are second to none and offer an outstanding environment for learning and growth.

There are many stakeholders I’d like to thank for their open feedback over the years. Your honesty was instrumental in helping us understand and balance the diverse views of industry in a way that continued to move the marketplace forward.

I’d also like to acknowledge the employees, management and executive team of the AESO and its predecessor companies for their unparalleled commitment, knowledge and integrity.

In closing I’d like to note with thanks for his service and support, that John Feick is leaving the Board this spring. In addition, I’d like to thank our past and current Board members for sharing your expertise and dedication to excellence in corporate governance. In my view, one of the greatest achievements of our collective Boards has been the development of a governance approach that is founded in continuous learning and creating stability within an environment of change.

I will be watching with great interest as the AESO continues to serve the industry, customers, stakeholders and employees with respect and continuing success.

F. Maury Parsons
AESO Board Chair
March 2006
The AESO plays a significant role in ensuring Alberta industry is well positioned to fully realize opportunities. Industry must be confident that the continued reliable and competitively priced supply of power is properly managed when deciding to invest in Alberta.

It’s been a year of many challenges and accomplishments for the AESO and its employees. We took significant steps to strengthen Alberta’s power grid this year, receiving regulatory approval for three major transmission system reinforcements — the 500 kV Edmonton to Calgary transmission development, the southwest system project and the City of Edmonton reinforcement. These approvals culminated years of study for our transmission planners, and required critical input and contribution from our operations, regulatory, finance and stakeholder relations teams. This approved transmission development represents more than half a billion dollars in investment.

Early in 2006, we filed a need identification document for about $300 million in transmission development in the northwest region by 2009. This application is unique in that we are also asking for approval for the advanced procurement of the right-of-way for future transmission development in the 2014 timeframe. We are taking this innovative approach to ensure that long lead-time critical transmission infrastructure keeps pace with growth.
As Alberta moves to become one of the primary global energy suppliers, the provincial economy will continue to grow, and with it, the demand for electricity. Alberta’s ability to realize its full economic potential depends, in part, upon the continued availability of reliable and competitively priced electricity.

This project was also a pilot for a comprehensive industry consultation process to gather stakeholder input and feedback at every stage in the development of our need application—thus delivering on our commitment to stakeholders to consult earlier and more often.

In our electric system operations area, a key focus has been increased diligence on our operations planning studies, development and implementation of enhanced real-time operating tools and ongoing training for our system controllers to ensure reliable operation of the transmission system.

Our operations role is more challenging today as the transmission system, which is in need of the previously mentioned reinforcements, is experiencing congestion, which requires us to ensure we have rigorously defined operating limits and operating policies and procedures.

In 2005, we received a strong endorsement from the North American Electric Reliability Council (NERC) and the Western Electricity Coordinating Council (WECC) teams that carried out a “readiness” audit of the AESO. The AESO is also leading critically important work with our industry partners to ensure our emergency preparedness plans are well coordinated and ready to meet the needs of the province.

The Transmission Regulation requires the AESO to ensure the interties with B.C. and Saskatchewan are restored to their design capability. Our major transmission system reinforcements, justified on the basis of reliability and system efficiency, will also take a significant step towards this requirement. In the meantime, we’ve made a concentrated effort to maximize the intertie capability of the existing system to facilitate the competitive market, without compromising system reliability.

On the market side of the business, our top priority has been to implement the recommendations of the government’s Electricity Policy Framework released in June 2005. During the last year, our consultative work focused on priorities identified in the policy and by stakeholders to increase stability and credibility of the market signal.

Going forward we will continue working with stakeholders on the issue of long-term adequacy of supply as well as other topics such as appropriate market participation rules for wind generation, reliability unit commitment, unscheduled energy flows, operating reserve market redesign, export market rules and alignment of the dispatch and settlement periods.

I invite you to read the following Year in Review sections for additional information about these initiatives and other key achievements in 2005.
AESO Executive

Standing left to right:
Kent McDuffie, Vice-President, Market Services | Neil Millar, Vice-President, Transmission |
Warren Frost, Vice-President, Operations & Reliability | Guy Heerema, Acting Vice-President, IT | Heidi Kirrmaier, Vice-President, Regulatory |

Seated left to right:
David Erickson, Senior Vice-President and CFO | Dale McMaster, President and CEO |

We are committed to delivering on our mandate – whether it's planning or implementing transmission projects to strengthen the provincial grid; maintaining reliability in a more challenging operating environment; efficiently connecting customers to the system; or working with stakeholders to implement refinements to our existing market framework.
As we look to 2006 and beyond, there will be increasing challenges for the AESO.

Over the past several years, Alberta’s energy resources have garnered international attention. As Alberta moves to become one of the primary global energy suppliers, the provincial economy, which has led the nation for the last number of years, will continue to grow and with it, the demand for electricity. Alberta’s ability to realize its full economic potential depends, in part, upon the continued availability of reliable and competitively priced electricity. In effectively fulfilling its mandate, the AESO is an important contributor to the economic objectives of the province and to the quality of life of Albertans.

Our key priorities over the next year will focus on achieving our mandate and the fundamentals of our business. While we’ll continue the diligent operation of the existing electric system, the timely interconnection of customers and the implementation of approved projects, we’ll also target to file several need applications for system reinforcement including a second 500 kV transmission line. The consideration of an additional intertie to a neighbouring jurisdiction will also be advanced.

On the market side of our business, we’ll continue to implement the Market Policy recommendations. As the implementation of the Market Policy recommendations progresses, our focus will shift to stabilizing the market and regulatory frameworks. To this end we will work with stakeholders to establish a comprehensive set of market performance metrics to objectively assess the performance of the market against objectives of the Market Policy. We will also work with stakeholders to develop a five-year market outlook to facilitate the evolution of the competitive market for electricity.

Reliable power, reliable markets, reliable people — that’s our objective. We are committed to delivering on our mandate and to building trust through stronger working relationships with industry stakeholders.

In closing I’d like to thank Maury Parsons, our Board Chair for his support, advice and strategic guidance over the years. During his eight years at the helm of the AESO and our predecessor companies, Maury has shown solid leadership. His counsel will be missed when he retires later this spring. I’d also like to thank stakeholders for their time and constructive feedback and the AESO team for their commitment, professionalism, enthusiasm and integrity.

M. Dale McMaster
AESO President and CEO
March 2006
Keeping the lights on throughout Alberta

We are focusing our efforts and expertise on the following priorities:

• Our team of operations engineers and system controllers ensure that the Alberta Interconnected Electric System (AIES) is operated in a safe, reliable and economic manner.

• We ensure that the Alberta interconnected power grid is planned and operated in compliance with applicable North American standards and reliability criteria.

• To enable the competitive electricity market and ensure reliable system operations, our teams, with stakeholder input, develop operating policies and procedures that are thoroughly documented and communicated to industry stakeholders.

• Through collaborative efforts with industry — generators, distribution and transmission facility owners — we coordinate and test our emergency preparedness plans, including system restoration plans, to ensure we are prepared for any emergency. It is our priority to make sure we have the best plans possible to recover quickly from, and mitigate the impacts of, an unexpected power interruption.

• Our system coordination centre (SCC) delivers operational excellence 24 hours a day, 365 days a year. A comprehensive training program ensures that our team of system controllers continues to enhance its operational expertise as Alberta’s power grid becomes more diverse and complex to operate.
A key component of our mandate is the safe, reliable and economic operation of the AES. This requires close collaboration with transmission facility owners (TFOs), distribution facility owners (DFOs) and generators.

Due to the fact that there has only been one major reinforcement to the transmission system during the past 20 years, the system has become increasingly stretched as the demand for power has grown in the province.

We face complex operating challenges that require heightened levels of due diligence to ensure that the lights stay on. The expertise of our operational team is critical.

AESO RECOGNIZED FOR BEST PRACTICES

In 2005, the North American Electric Reliability Council (NERC) and the Western Electricity Coordinating Council (WECC) carried out a “readiness assessment” on the AESO.

The NERC was formed in 1968 to ensure the transmission system in North America is reliable, adequate and secure. In fulfilling its role, the NERC will: set standards for the reliable operation and planning of the bulk electric system; monitor, assess and enforce compliance with reliability standards; conduct reliability readiness audits of bulk electric system operators to ensure that they are capable of complying with the NERC standards.

The Western Electricity Coordinating Council (WECC) is responsible for coordinating and ensuring a reliable electric power system in the Western interconnection. The WECC supports efficient competitive power markets, assures open and non-discriminatory transmission access among members, and provides a forum for resolving transmission access disputes.

The NERC/WECC audit teams gave the AESO a strong endorsement, concluding that the AESO is operationally well prepared. In their final report the auditors recommended to the NERC that three of our practices should be recognized as “industry best practices” and acknowledged that our documentation in preparation for the assessment, including our operating policies and procedures (OPPs), was some of the best they have seen. In today’s challenging operating environment, this strong endorsement is a welcome confirmation that we are taking the right steps to ensure system reliability.

All of our system controllers are NERC/WECC certified and the AESO is certified as a NERC continuing education provider. Our training programs and simulators have served as a model for other control area operators in the NERC/WECC.
During the past year we have carried out extensive operations planning studies. The results of these studies were incorporated into our OPPs and our ongoing system controller training programs.

With industry input, more than 20 of our OPPs were enhanced to reflect today’s operating environment. Real-time operating tools for our system controllers were also developed or enhanced to better manage the increased operating complexity.

The operating challenges will continue to grow until a major transmission system reinforcement, in the form of the 500 kV Edmonton to Calgary transmission line development, is implemented.

In addition to dealing with today’s complex operating environment, our industry, like many others, faces human resources challenges. The electric power industry faces a shortfall of skilled personnel and has lagged in attracting young people into the industry.

In 2005 we established a partnership with the Southern Alberta Institute of Technology (SAIT) to incorporate power system operations training into their programs for technologists. This is a significant step to attract young people to a career in the electric power industry and ensure a long-term source of power system analysts and system controllers.

ENSURING A SOLID RELIABILITY FRAMEWORK IN ALBERTA

In mid-2005, we established a joint effort with the TFOs to develop over-arching principles and criteria for appropriate operational and maintenance and to clarify roles amongst the AESO and TFOs respecting reliability. We continue to meet regularly and are making good progress on over-arching principles and standards and a thorough assessment of industry-wide emergency preparedness.

There is a concerted effort underway to implement mandatory reliability standards in the U.S., which will affect the Canadian electricity industry. Key AESO personnel have been involved on various committees and task force groups involved in this initiative.

In addition, we are collaborating with Alberta Energy, the Alberta Energy and Utilities Board (EUB) and others on coordinated provincial responses for draft rule making proposals in the U.S. The AESO also contributed to other submissions filed with the Canadian Electricity Association, the North American Independent System Operators/Regional Transmission Organization Council and the WECC. In collaboration with the governments of Alberta and B.C., the AESO was successful in advocating for Canadian representation on the WECC Board of Directors.

More information about our collaborative work in this area can be found on our website www.aeso.ca.
MEETING MORE STRINGENT SECURITY REQUIREMENTS
Another key element in our capability to deliver reliable system operations and meet expected new legislated standards for system security is the development and construction of a new $20-million system coordination centre.

The challenge with a project like this is maintaining a schedule and budget in a province where there is a huge demand for construction materials and labour. The AESO used competitive tendering throughout the project coupled with rigorous contract management, to effectively manage project risk. We expect to be operating the competitive market and Alberta’s electric system from our new facility before the end of 2006.

LEADING INDUSTRY WORK ON SYSTEM RESTORATION
During 2005, the AESO spearheaded industry-wide efforts to test and refine our emergency response and electric system restoration plans. This work culminated in an industry-wide system restoration drill in the fall of 2005. This important work has led to key improvements to the AESO’s plan, enhanced the coordination across our industry, and improved our preparedness and ability to restore power in the event of an unexpected interruption.

COMPETITIVE PROCUREMENT OF ANCILLARY SERVICES AND MAXIMIZING INTERTIE CAPABILITY
In cooperation with market participants and the Market Surveillance Administrator, the AESO has developed and implemented a competitive procurement process for ancillary services. This process will significantly increase transparency and provides a dispute resolution mechanism.

Interties with neighbouring jurisdictions are critical to the success of Alberta’s competitive electricity market and to the reliable operation of the electric power system. During the past several years the amount of power that can be transferred on the interties has dropped significantly below the intertie’s original design capability and a major reinforcement of the transmission system is required to restore this capability.

In the interim, the AESO is committed to maximizing the capability of the interties without compromising system reliability. During the past year, in close cooperation with market participants, we have spent considerable time and effort on developing and refining the operating limits, real-time operating tools, OPPs and system models with the objective of maximizing the interties’ capability.

In addition, the AESO commissioned several major capacitor bank installations in the Calgary area, which has improved the voltage stability of the system and removed one of the factors limiting intertie capability.

This work to maximize the use of our existing interconnections will continue to be a priority for us in 2006. That being said, we must emphasize that interim measures are expected to provide only incremental increases in intertie capability or maintain existing capabilities as the system load continues to grow. A major increase in capability on the interties will only be realized with the reinforcement of the transmission system.

Karla Denby  
Customer Services

Nebiyu Yimer  
Transmission

Greg Rahn  
System Operations
The AESO also concluded a comprehensive consultation with stakeholders in 2005 to implement new loss factors. In Alberta, generators are responsible for the cost of system losses and loss factors are used to allocate these costs to the individual generators. The AESO, in consultation with stakeholders, developed a loss factor calculation methodology to comply with the requirements of the Transmission Regulation. The resulting loss factors for 2006 were implemented on January 1.

INTEGRATING WIND POWER
A significant amount of wind power generation has been added in Alberta over the past several years with substantial new wind capacity proposed for development in the upcoming years.

A major challenge facing the industry and the AESO is to establish the appropriate framework to facilitate the integration of the province’s wind generation potential into the competitive electricity market and reliably integrate it into the electric power system. These challenges arise from the variability of wind generation (power is only produced when the wind blows) and the somewhat unique electrical characteristics of the technology. These are challenges being faced by system operators across North America.

In 2005 the AESO, in cooperation with wind power developers, carried out a study of wind power variability using data provided by wind developers. The study, published in November 2005, determined that the variability of wind generation may create reliability concerns for the system operator, particularly as the amount of wind generation exceeds a certain threshold.

Reliability concerns resulting from the variability in wind generation begin to occur with about 900 MW of wind on the system. This is in general alignment with an industry “rule of thumb” that operating issues become apparent when installed wind power approaches 10 per cent of the system capacity.

A second study was initiated to examine ways to mitigate the impact of wind variability on system operations. At the time of the writing of this report, the AESO has completed the study and is about to publish the results. Meetings will be held with stakeholders to discuss the implications.

The success of the wind industry in advancing both the technology and projects for development has highlighted the need to address the issues associated with wind generation.

The AESO is committed to working with stakeholders and wind developers to ensure a level playing field to accommodate wind generation in the competitive electricity market and reliably integrate it on the electric system. Further work is required to refine the mitigation measures, determine their costs and develop an appropriate cost-recovery mechanism. We look forward to this ongoing challenge.
We are focusing our efforts and expertise on the following priorities:

• Our experienced team of transmission planners is proactively planning, achieving approvals for, and initiating implementation of transmission system reinforcements to strengthen Alberta's grid and ensure a reliable and economic power system.

• Our plans to reinforce Alberta's interconnected transmission grid will restore and enhance import and export capabilities. This in turn is a positive step towards greater reliability and operational flexibility for our system, and encouraging investment in future supply and economic development for Alberta.

• We provide non-discriminatory access to Alberta's power system. Our interconnection team is working to ensure that customer requirements are met through a process that is efficient and results in the timely delivery of a quality product.
It’s our job to make sure Alberta has a transmission system that delivers reliable power when and where Albertans need it. The power grid must meet the challenges of a growing provincial economy and increasing demands for reliable electricity for Alberta’s industry, business and residential consumers.

Alberta’s electricity industry, like many others, is in a major investment cycle to strengthen and reinforce the power grid. Only one major transmission line has been built in the province during the last 20 years. The grid is reaching its design limits and we are working to maximize the capability of our existing system to maintain reliability while we build new facilities.

It’s our job to carefully and prudently plan the system to meet stringent technical and reliability standards. Our best response to these challenges is to make sure that Alberta has a robust and geographically diverse transmission system.

EDMONTON TO CALGARY 500 KV TRANSMISSION DEVELOPMENT

In April 2005, the EUB approved the AESO’s need application for the Edmonton to Calgary 500 kV Transmission Development. In its approval, the EUB stated that the AESO’s recommended option was “superior” in all aspects, including improving system efficiency and reliability, enabling the development of new power generation in the province, and facilitating competitive electricity markets.

The EUB approval of this project was a major achievement for the AESO and its employees that resulted from the culmination of more than two years of work and required the talents of employees from across the organization.

The new transmission line is the most significant transmission development the province has seen in 20 years. It will provide much needed reinforcement to the electric power system. The importance of this development from the perspective of system reliability cannot be overstated. In addition to enhanced reliability, the new line will result in a significant reduction in transmission system losses and the associated costs — loss savings of about 120 MW, the approximate load demand of a city the size of Red Deer.

Strengthening the transmission facilities in this corridor — the backbone of Alberta’s grid — sends a strong signal to generation developers that the transmission system will be developed to keep pace with growing demand in the province. This will encourage new investment in supply as developers will have confidence that their product can be reliably taken to the market place. It is also a strong signal to consumers generally and, in particular to those that depend on reliable and economic electricity to compete in the global marketplace, that the system will be developed to meet their needs.
While justified on the basis of reliability and loss savings, the line will also be a significant step towards restoring the capability of the intertie with B.C., with the associated benefits to the competitive electricity market and system reliability. Full restoration of the intertie capability will require the construction of a second 500 kV transmission line, as noted in our 2004 10-Year Transmission System Plan.

The first component of the Edmonton to Calgary 500 kV project will see two existing transmission lines between the Keephills and Genesee generating stations west of Edmonton and the Ellerslie substation south of Edmonton upgraded from 240 kV to 500 kV operation. The lines were originally built to operate at 500 kV but have been operating at 240 kV. The anticipated in-service date for these facilities is 2007.

The second component involves building a new 330-kilometre, 500 kV transmission line from the Genesee generating station to an existing substation at Langdon east of Calgary. The targeted in-service date is 2009. The current total estimated cost of both components is about $450 million (as spent 2009 dollars).

The transmission facility owners, AltaLink and EPCOR, are preparing to file facility applications for the first component of the project in the second quarter of 2006. We expect the facility application for the second component of the development, the new 500 kV transmission line, to be filed in the summer of 2006.

The building of a transmission project of this magnitude is a major challenge. One of the key challenges is the procurement of the right-of-way. While the implementation challenges fall primarily to AltaLink, the transmission facility owner, the AESO is committed to supporting the regulatory process to help ensure issues are addressed appropriately.

As part of our commitment to provide timely information about major transmission developments, we host information meetings about our major projects and plans, and publish information on a regular basis to our website at www.aeso.ca.

SOUTHWEST ALBERTA TRANSMISSION DEVELOPMENT

In May 2005, the AESO received EUB approval for a $95-million (as spent 2007 dollars) reinforcement to increase system capacity, enhance reliability and interconnect wind power projects in southwestern Alberta. This reinforcement includes the expansion of existing substations, two new 240 kV transmission lines and smaller transmission line upgrades. AltaLink will build the facilities, which are targeted for an in-service date of early 2007.

The AESO has interconnected about 330 MW of wind farms in the southwest during the last five years. This transmission development will enable additional wind projects to interconnect to the grid.
CITY OF EDMONTON TRANSMISSION DEVELOPMENT

In July 2005, the EUB approved the AESO’s need application for a major reinforcement of the transmission system serving the City of Edmonton. This development will provide a diversified source of supply for the Edmonton city centre.

The AESO recommended a new 10-kilometre, 240 kV underground transmission line from Castle Downs substation to the Victoria substation. An underground line was recommended due to the urban setting, lack of right-of-way, and costs. Total estimated cost of the facilities required is $54 million (as spent 2008 dollars). The development is targeted to be in service in the fall of 2008.

NORTHWEST ALBERTA TRANSMISSION DEVELOPMENT

In April 2005 the AESO initiated a comprehensive industry stakeholder consultation process to develop a transmission need application for the northwest region. At each stage of the process – need identification, alternative screening and alternative assessment and recommendation development – the AESO sought input from industry stakeholders. In some cases this occurred in one-on-one meetings, small group meetings, email and publication of input on the AESO’s website. We have received positive feedback from stakeholders on the consultation process. We are confident that this has resulted in a better need application that will in turn result in a more focused and efficient hearing.

In March 2006, we filed our northwest need identification document with the EUB. The application identifies $33 million in upgrades by 2007 and a $263 million reinforcement (including four new transmission lines) by 2009. The AESO is also asking for approval to proceed to have a right-of-way acquired for future development in the 2014 timeframe, at an estimated cost of $2.5 million. In addition to meeting load growth and delivering the best operational performance, the application also allows for the elimination of between $35 and $45 million in annual transmission must-run (TMR) payments.

PLANNING STUDIES UNDERWAY

Electricity is one of the cornerstones for Alberta’s ongoing economic growth and a critical piece of public infrastructure to ensure the quality of life for its citizens. Electricity becomes even more important as Alberta becomes “the” supplier of energy for North America.

In 2006, the transmission planning group is moving forward on key planning studies for a second north-south 500 kV transmission line, reinforcements for the southeast and northeast part of the province and the major cities of Calgary and Edmonton. We will also initiate planning studies to evaluate the need for additional interties with neighbouring jurisdictions. We intend to use and refine the consultation process developed for the Northwest Alberta Transmission Development in our ongoing planning initiatives.
LONG-TERM PLANNING
The AESO completed its first 20-year Transmission System Outlook in June 2005. This long-term outlook examined alternative load growth and generation development scenarios, then identified the transmission system reinforcements that would be required to support this development. The AESO uses the 20-year Outlook to provide context and direction for its more detailed 10-year Transmission System Plan and need applications. The 10-year Transmission System Plan will be updated in 2006.

A key finding of the 20-year Outlook was that about 7,000 MW of new generation will be required to meet the “most likely” load forecast. This 7,000 MW excludes considerations of behind-the-fence load and offsetting generation. To integrate this generation and to restore the intertie capability of the system as required by the Transmission Regulation, a second 500 kV north-south transmission line and a 500 kV transmission line into the Fort McMurray area will be required. Further, significant 240 kV reinforcements will be required for the areas in and around Grande Prairie, Lloydminster, Lethbridge, Medicine Hat, and for the major cities of Edmonton and Calgary. The 20-year Outlook also contemplated the possibility of a future intertie with B.C., which as previously noted will be the subject of further study.

FACILITATING MERCHANT TRANSMISSION IN ALBERTA
The Transmission Regulation requires the AESO to establish a framework to facilitate the development of merchant transmission interties with neighbouring jurisdictions. The AESO has undertaken the development of this framework in parallel with work being done with Montana Alberta Tie Ltd. on their proposed 300-kilometre, 240 kV merchant intertie (MATL) between Montana and Alberta.

The framework will address issues including but not limited to the rules for open access to merchant transmission capacity in Alberta; feasibility studies and detailed engineering to assess the technical and operational impact on the Alberta electric power system; development of tariffs for merchant transmission line interconnections; and for “firm” export and import transmission service.

The Transmission Regulation requires the AESO to submit a need application to the EUB for proposed merchant transmission developments. The AESO files not as the proponent but rather to ensure that the impacts of the merchant transmission line are considered and the line is properly integrated into the Alberta electric power system. We expect to file the need application for the MATL line in the second quarter of 2006.
IMPROVING THE CUSTOMER INTERCONNECTION PROCESS

In March 2005, the AESO in collaboration with transmission facility owners (TFOs) completed a comprehensive review and redesign of the transmission customer interconnection process. The interconnection process outlines the interaction between customers, TFOs, the EUB and the AESO. The AESO manages this process to ensure that all customers are provided with open and fair access to the transmission grid while maintaining the overall reliability of the system.

Customers and stakeholders from each organization and agency involved in the process participated in the redesign to ensure that efficiencies could be captured and implemented across all aspects of the process. The overall objective was to improve customer satisfaction and streamline the process to be more effective.

We are about six months into implementation of the process and indications are that the new process is delivering the desired results. The EUB and transmission facility owners as well as our own staff are seeing the benefits of a clearer and more efficient process, and most importantly, so are our customers.

We are also experiencing a busy year for interconnection applications. Our interconnections team is currently working with about 100 active transmission system access applications, a third of which were received in the last quarter of 2005. On average, we receive 50 to 60 applications over the period of one year. One driver for the large volume of applications received in the last quarter of 2005 was the year-end expiry for the AESO’s transmission tariff. A new tariff came into effect on Jan. 1, 2006.

EXPLORING REGULATORY EFFICIENCIES

In late 2005, the AESO began to work with the EUB on a collaborative process to identify efficiency improvements in the regulatory process for customer/generator interconnections and smaller system projects under $10 million.

In March 2006 the EUB and the AESO jointly announced that this collaboration had in fact led to processes to move transmission projects through the permitting process in a timely fashion while continuing to provide oversight that appropriately balances the interests of all stakeholders.

As of April 1, 2006, the AESO will file need documents for customer/generator interconnections and smaller system projects under $10 million with the EUB for information purposes only. The EUB will provide notice to stakeholders of the AESO’s information filings without a review. However if a stakeholder objection is filed, the EUB will decide if the AESO is required to file a need application.
Building confidence in Alberta’s market

We are focusing our efforts and expertise on the following priorities:

- Ensuring that Alberta’s competitive electricity markets are sustainable, predictable and adding long-term value.

- Reliable markets:
  - fair, efficient and openly-competitive power markets
  - price fidelity and a trusted market price signal
  - transparent reporting of supply adequacy signals

In early 2005, the AESO was actively involved in the final stages of Alberta Energy’s wholesale market review consultation process. Throughout the review our team made a significant contribution with respect to the appropriate market changes and potential impacts and implementation challenges.

The government released its final policy paper in June 2005. The policy framework recognized that “Alberta’s competitive electric market framework has been successful to date” and that “significant new investment has been made in the industry and a variety of new players are participating in the electricity markets”.

While the wholesale market review considered other market structures, the final policy was to maintain the energy-only market structure and to focus on incremental enhancements.

The government’s policy focused on improvements in the following key areas:

- Refinements to existing market with the objective of the stability and credibility of the price signal;
- The need for supplemental market signals to ensure long-term adequacy of supply.
IMPLEMENTATION OF MARKET REFINEMENTS UNDERWAY

After the release of the policy framework, the policy working group was re-established to focus on the short-term adequacy (STA) items noted in the policy. The AESO assumed the Chair of this new working group, which included wholesale market participants representing suppliers and consumers as well as representatives from Alberta Energy.

The purpose of the STA working group was to act as an idea-generating and vetting forum for the detailed designs to implement the specific recommendations included in the government’s policy framework.

The policy framework contained numerous recommendations. The AESO, in conjunction with Alberta Energy, established an implementation plan based on segmenting the recommendations into three stages for implementation.

The first stage, known as the ‘quick hits’, were aimed at improving price signals for market participants and enhanced supply visibility for the AESO’s system controllers. These included:

- must-offer requirements for generators and their obligation to comply with dispatch instructions.
- restatements of offers would only be allowed up to two hours before the start of the delivery hour.
- marginal generators dispatched within the hour would be paid the greater of their offer price or the market’s clearing price.
- imports, which now offer in at $0/MWh, would be allowed to set pool price.
- pool price re-constitution would be instituted to mitigate the impact of energy produced by must-run generators on the pool price.

The AESO, Alberta Energy and stakeholders have subsequently been involved in an extensive dialogue regarding the appropriate implementation of these recommendations. The documents resulted in a series of conceptual documents, known as ‘term sheets’, which were drafted and released in the fall of 2005. Additional consultation and feedback led to the development of the draft rules, which we expect to be finalized and implemented in the second quarter of 2006.
In the fall of 2005, the AESO began stakeholder consultation on the long-term adequacy portion of the policy, which proposed the creation of adequacy metrics that the AESO would use to track whether there is sufficient generation capacity to meet Alberta’s needs into the future. We support the concept that the energy only market price signal should be supplemented by other market signals that reflect the adequacy of available supply on an ongoing basis. While it is clear that unreliable and inadequate supply is not acceptable, the AESO is confident that with the proper signals and a trusted price index the market will respond and new supply will develop when it’s needed.

We are committed to working with stakeholders to develop appropriate long-term adequacy metrics and a transparent monitoring and reporting mechanism.

**FUTURE WORK**

As part of its overall implementation plan communicated in August 2005, the AESO and Alberta Energy outlined future work that would be undertaken. The AESO is currently working with stakeholders to develop proposals to address the work in stage two and stage three of the policy framework implementation. This work will include, but not be limited to, such issues as reliability unit commitment; unscheduled energy flows; export market rules; integration of wind generation into the competitive market; ancillary services self procurement; and alignment of dispatch and settlement periods.
Price Summary Statistics

The average Alberta wholesale pool price was up 28.9 per cent from 2004, averaging $70.35/MWh in 2005. On-peak prices increased 36.8 per cent over 2004. Conversely, 2005 off-peak price increased by 17.1 per cent over 2004 levels.

Average Pool Prices

The first half of 2005 was a continuation of the relative pricing levels from the prior year as average price stayed in a relatively tight band around the $50/MWh mark without significant variation in on- or off-peak prices. Conversely, in the second half of 2005, and the fourth quarter of 2005 in particular, prices increased dramatically as did the variance between on- and off-peak prices.
Supply and Demand

The Alberta market is interconnected with other markets through interties with B.C. and Saskatchewan. These interties allow price signals from other markets to be communicated to Alberta, and vice-versa. Import and export activity varies during the on- and off-peak periods of the day. In 2005, Alberta tended to import from B.C. during on-peak hours, and export to B.C. during off-peak hours. Overall, Alberta continued to be a net importer of electricity with an increase in imports of 2.9 per cent and a decrease in exports of 2.2 per cent as compared to 2004 levels.

Alberta’s internal load (AIL) has increased due to sustained increases in population and economic growth. Alberta’s real GDP is expected to increase 4.2 per cent over 2004. Population growth was 1.6 per cent compared to 1.4 per cent in 2004. Internal load growth was relatively low at 1.5 per cent. A record Alberta internal load peak of 9,580 MW was reached on Dec. 5, 2005. This was a 3.7 per cent increase over the previous peak of 9,236 MW set in December 2004.

Supply and Demand Statistics

<table>
<thead>
<tr>
<th>Category</th>
<th>2000</th>
<th>2001</th>
<th>2002</th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
</tr>
</thead>
<tbody>
<tr>
<td>AIL Internal Load (MWh)</td>
<td>54,052,857</td>
<td>54,464,397</td>
<td>59,427,895</td>
<td>62,714,018</td>
<td>65,261,309</td>
<td>66,266,568</td>
</tr>
<tr>
<td>Average Hourly Load (MW)</td>
<td>6,154</td>
<td>6,217</td>
<td>6,784</td>
<td>7,159</td>
<td>7,430</td>
<td>7,565</td>
</tr>
<tr>
<td>Maximum Hourly Load (MW)</td>
<td>7,785</td>
<td>7,934</td>
<td>8,570</td>
<td>8,786</td>
<td>9,236</td>
<td>9,580</td>
</tr>
<tr>
<td>Minimum Hourly Load (MW)</td>
<td>4,999</td>
<td>5,030</td>
<td>5,309</td>
<td>5,658</td>
<td>6,017</td>
<td>6,104</td>
</tr>
<tr>
<td>Year-over-Year Load Growth</td>
<td>–</td>
<td>0.76%</td>
<td>9.11%</td>
<td>5.53%</td>
<td>4.06%</td>
<td>1.54%</td>
</tr>
<tr>
<td>Load Factor</td>
<td>79.0%</td>
<td>78.4%</td>
<td>79.2%</td>
<td>81.5%</td>
<td>80.4%</td>
<td>79.0%</td>
</tr>
</tbody>
</table>

B.C. and Saskatchewan Intertie Statistics

<table>
<thead>
<tr>
<th>MWh</th>
<th>2000</th>
<th>2001</th>
<th>2002</th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
</tr>
</thead>
<tbody>
<tr>
<td>Imports on B.C. Intertie</td>
<td>564,238</td>
<td>232,052</td>
<td>895,753</td>
<td>898,717</td>
<td>1,073,471</td>
<td>1,070,848</td>
</tr>
<tr>
<td>Imports on Sask. Intertie</td>
<td>742,704</td>
<td>676,130</td>
<td>239,406</td>
<td>428,949</td>
<td>418,267</td>
<td>463,726</td>
</tr>
<tr>
<td>Total Imports</td>
<td>1,306,942</td>
<td>908,182</td>
<td>1,135,159</td>
<td>1,327,666</td>
<td>1,491,738</td>
<td>1,534,574</td>
</tr>
<tr>
<td>Year-over-Year Growth</td>
<td>–</td>
<td>-3.01%</td>
<td>24.99%</td>
<td>16.96%</td>
<td>12.36%</td>
<td>2.87%</td>
</tr>
<tr>
<td>Exports on B.C. Intertie</td>
<td>440,315</td>
<td>1,974,107</td>
<td>465,939</td>
<td>1,194,264</td>
<td>968,434</td>
<td>987,581</td>
</tr>
<tr>
<td>Exports on Sask. Intertie</td>
<td>6,665</td>
<td>63,388</td>
<td>105,337</td>
<td>32,903</td>
<td>92,940</td>
<td>50,493</td>
</tr>
<tr>
<td>Total Exports</td>
<td>446,980</td>
<td>2,037,495</td>
<td>571,276</td>
<td>1,227,167</td>
<td>1,061,374</td>
<td>1,038,074</td>
</tr>
<tr>
<td>Year-over-Year Growth</td>
<td>–</td>
<td>-35.58%</td>
<td>-71.96%</td>
<td>114.81%</td>
<td>-13.51%</td>
<td>-2.20%</td>
</tr>
<tr>
<td>Net Yearly Total</td>
<td>859,962</td>
<td>-1,129,313</td>
<td>563,883</td>
<td>100,499</td>
<td>430,364</td>
<td>496,500</td>
</tr>
</tbody>
</table>
Energy Production by Fuel Source

Since 2000, Alberta has added significant cogeneration capacity, as well as additional wind farm projects and the Genesee unit #3 coal-fired unit. There have also been retirements of generating capacity during this period, such as Battle River units #1 and #2 in 2000, the Wabamun #1 and #2 units at year end 2004 and the gas-fired Clover Bar units in 2005. Cogeneration, wind and coal-fired generation have increased as a proportion of energy production during this time period. Conversely (non cogeneration related) gas-fired generation has fallen as a proportion of energy production by fuel source.

The Relative Value of Electricity and Natural Gas in Alberta

A spark spread is the difference between the price of electricity sold by a generator and the cost of the fuel used to generate that electricity, adjusted for equivalent units. The following chart illustrates the effect decreasing market heat rate (for definition see page 40) has had on generators with unit heat rates of 7, 9, & 11 GJ/MWh, respectively. In all cases there has been a decrease in profitability. For example, in 2000 a gas-fired generator with a 9 GJ/MWh heat rate would have been able to operate profitably in all months of the year. By 2005, that same generator would have been able to operate profitably for only three months of the year.

Heat rates are used in this analysis to net out the effect of natural gas price changes on electricity prices. This is important as gas prices exhibit considerable volatility over time. For example, the average gas price changed from $6.22/GJ in 2004 to $8.26/GJ in 2005. Moreover, during 2005 gas prices increased from an average of $6.53/GJ in Q1 to an average of $10.72/GJ in Q4.

The Relative Value of Electricity between Alberta and Mid-Columbia U.S.

Alberta is a market interconnected with other jurisdictions by way of its interties to Saskatchewan and British Columbia. The primary external electricity price signal to which the Alberta market reacts is the Mid-Columbia Electricity Price Index (MidC). This chart shows the spread between the MidC and the Alberta pool price in C$/MWh from 2003 to 2005. It also illustrates the effect such price differentials may have on flows between different jurisdictions (notwithstanding other considerations such as capacity limitations). In particular, the analysis only incorporates flows of energy that occur when the price differential between MidC and the pool price is greater than +/- $10/MWh, as it is unlikely price differentials smaller than this would induce energy flows in either direction. In general, this analysis suggests a correlation between price differentials and energy flows. For example, the analysis shows that for Q1/2005 MidC prices were generally higher than pool prices. During this period, Alberta was a net exporter. Conversely, in Q4/2005, pool price tended to be significantly higher than MidC prices. During this period, Alberta was a net importer of electricity.
Alberta Wholesale Market Statistics

Price Setter by Company
This chart looks at the frequency that each firm sets price from 2000 to 2005. It would appear that since 2000 the pool price has been set by various different participants — there has not been one singularly dominant entity that has set price. 2005 appears to have been a relatively typical year in terms of the relative distribution of price setting companies in the market. We note the distribution appears to be much more diffuse in this chart than in the Energy Production by Company chart. This may suggest that the ability to set price in the Alberta electricity market is not wholly dependent on the size of the firm in the market.

Price Setter by Fuel Source
The difference between 2004 and 2005 in the price setting by fuel source mix is arguably the largest since 2000 and 2001, when imports were no longer able to act as price setters. In 2005, the proportion that hydro, cogeneration and coal fuel source assets set price increased significantly while the proportion that gas-fired generators set price decreased. This may be a function of the relatively high natural gas prices observed during 2005 and the associated increased variable cost of gas-fired generation.

Energy Production by Company
The chart on page 29 shows the relative market share in the Alberta electricity market as determined by the energy production by company. We note there has been little change in relative market share by company since 2000. In terms of total volumes generated, the market continues to be dominated by five different companies, as well as generation administered by the Balancing Pool.

* Company information is confidential
AESO Board

Maury Parsons  
Board Chair

Maury Parsons, who began his appointment in 1998, has more than 25 years of experience in the Calgary business community and has held a number of senior positions in the energy, technology and investment industries. Over the past nine years, Mr. Parsons was executive-in-residence in the Faculty of Management at the University of Calgary, mentoring students and faculty on entrepreneurship. He has also lectured at the Banff School of Management and the Alberta Executive MBA program.

Bill Burch  
Board Vice-Chair

Mr. Burch joined the AESO Board in 2001. He is a chartered accountant with extensive background in the finance industry, including his position as managing partner of Coopers & Lybrand in Edmonton. Mr. Burch is a member of the Capital Health Region Board and a director of Floron Food Services Limited.

Dr. John Feick  
Audit Committee Member

Dr. John Feick joined the AESO Board in 2003. Dr. Feick brings extensive technical and energy industry experience in operations, finance, regulatory and strategic planning. He is Executive Chairman of Matrix Solutions Inc., an environmental services company and chairman and partner in Kemex Engineering Ltd. Dr. Feick serves on several boards including Occidental Petroleum Corporation (USA), Fort Chicago Energy Partnership, Alliance Pipeline Ltd. and Aux Sable Liquid Products Inc.

Dr. Ron George  
Human Resources Committee Member

Dr. George joined the AESO Board in 1999 and has more than 40 years of experience in the information technology business. Dr. George is an executive-in-residence at the University of Calgary, Faculty of Management. He is also a former member of the Board of Regents at Concordia University College in Edmonton and the Board of Lutheran Life in Waterloo, Ontario.
Harry Hobbs
Chair, Human Resources Committee
Harry Hobbs joined the AESO Board in May 2004. His 25-year tenure with Foothills Pipeline Ltd. has gained him extensive experience in commercial and customer interests, government and regulatory affairs, strategic planning, environment, socio-economics, rates and tariffs, economic planning, corporate communications and community investment. Mr. Hobbs currently serves as a director on the boards of the Van Horne Institute, an organization dedicated to addressing transportation issues in North America, and Teague Exploration Inc., an oil and gas exploration company located in Calgary.

Nancy Laird
Human Resources Committee Member
Nancy Laird joined the AESO Board in June 2003. Ms. Laird has held senior executive positions in several major energy companies and has a diverse background in managing energy trading and market portfolios, investment banking and IT, and futures trading. Ms. Laird serves as a board member of United Way of Calgary and Hull Child and Family Services. She is a former board member of Canadian Oil Sands Trust, Southern Alberta Institute of Technology, Alliance Pipeline and ProGas.

Bob McKenzie
Chair, Audit Committee
Bob McKenzie joined the AESO Board in June 2003. Mr. McKenzie took part in building several large companies, including the energy trading and telecommunications firms Northridge Petroleum Marketing and MetroNet Communications. Mr. McKenzie has served on the board of directors for several public and private companies and non-profit foundations.

Murray Nelson
Audit Committee Member
Murray Nelson joined the AESO Board in October 2004. Mr. Nelson brings a depth of experience in the electrical industry in Alberta and other international jurisdictions. He was the chief executive officer of New Zealand’s largest electricity retail company and served as a senior executive in Canada’s largest investor-owned electricity utility.
Dale McMaster was appointed President and CEO in June 2005. Mr. McMaster held the position of Chief Operations Officer for the AESO, and served as the Executive Vice-President of Operations & Reliability since the company's inception in 2003. He also held executive positions at the AESO's predecessor companies, the Power Pool of Alberta and Transmission Administrator of Alberta. Mr. McMaster is an electrical engineer with more than 30 years of experience in power system investment planning, operations, transmission system maintenance, and electric utility management in Canada and abroad.

David Erickson was appointed Senior Vice-President and CFO in June 2005. Having been CFO since 2003, Mr. Erickson assumed additional senior responsibilities in February 2005. He also held the position of CFO for the former Transmission Administrator of Alberta. A member of the Canadian Institute of Chartered Accountants and the Institute of Chartered Accountants of Alberta, Mr. Erickson has nearly 20 years of international financial management and accounting experience in the electricity and energy sectors.

Warren Frost was appointed Vice-President, Operations & Reliability in July 2005. Mr. Frost's responsibilities include operational planning and ensuring the safe, reliable and economic operation of Alberta's interconnected power system. Before joining the AESO, Mr. Frost was Director, Infrastructure Policy with Alberta Energy, Electricity Division. Mr. Frost is an electrical engineer with 29 years of experience in the electricity industry including policy development, system operations, transmission asset management, regulatory and customer service.

Heidi Kirrmaier was appointed Vice-President, Regulatory in December 2005. Ms. Kirrmaier is accountable for regulatory affairs at the AESO, which includes overseeing the consultation, design and implementation of the AESO's tariff and other proceedings regulated by the Alberta Energy and Utilities Board. Ms. Kirrmaier was Director, Regulatory Affairs and Manager, Rate Design and Forecasting at Aquila Networks Canada. She also gained extensive experience during her 11 years with ATCO working in a variety of regulatory roles in Edmonton, Calgary, Australia and England.
Kent McDuffie
Vice-President, Market Services

Kent McDuffie was appointed Vice-President of Market Services in May 2005. Mr. McDuffie’s key responsibilities are to build consensus within industry; to develop and implement strategic consultative processes with stakeholders in the area of AESO’s market services, and to ensure market participants are supported in the appropriate use and interpretation of the wholesale electricity market rules. Prior to joining the AESO, Mr. McDuffie was the Vice-President of Power Trading for Engage Energy. He held similar trading positions with Houston-based El Paso Energy and Duke/Louis Dreyfus LLC.

Neil Millar
Vice-President, Transmission

Neil Millar was appointed Vice-President of Transmission in April 2004. In this role, Mr. Millar is accountable for the strategic planning of Alberta’s interconnected electric grid, including the AESO’s 20-year Outlook, 10-year Plan and individual need applications to upgrade and strengthen the provincial power system. Previously, Mr. Millar was Director of Regulatory Affairs with the AESO, a position he held since 2003. He joined the AESO in May 2002 as Director of Electric System Operations after being with TransAlta Utilities for 19 years in a number of transmission planning, regulatory and customer services roles.

Guy Heerema
Acting Vice-President, Information Technology

Guy Heerema was appointed Acting Vice-President of Information Technology in December 2005. Mr. Heerema is accountable for the corporate IT department, which includes the planning, design, implementation, maintenance and support for the diverse and critical IT applications used to help ensure the open, efficient operations of the energy market and the overall coordination of the interconnected electric system in Alberta. Mr. Heerema brings 16 years experience as a senior leader of IT organizations in major oil and gas companies working both in Canada and internationally.
Management’s Discussion and Analysis of Financial Condition and Results of Operations

This management discussion and analysis of financial condition and results of operations (MD&A) should be read in conjunction with the Alberta Electric System Operator (AESO) audited financial statements for the years ended Dec. 31, 2005 and 2004 and accompanying notes. The MD&A and financial statements are reviewed and approved by the AESO Audit Committee and the AESO Board. The AESO financial statements have been prepared in accordance with Canadian generally accepted accounting principles and are expressed in Canadian dollars.

The AESO is responsible for the operation of Alberta’s competitive power pool; determining the order of dispatch of electric energy and ancillary services; providing system access service on the electric transmission grid; directing the safe, reliable and economic operation of the interconnected electric system; planning the capability of the transmission system to meet future needs; and regulating and administering load settlement.

1. AESO GOVERNANCE

The AESO is governed by the AESO Board, whose members are appointed by Alberta’s Minister of Energy (the Minister) and are independent of any person or entity having a material interest in the Alberta electric industry. In accordance with the AESO bylaws, the AESO Board must recommend to the Minister individuals to be appointed as members and may recommend to the Minister an individual to be designated as Chair. The AESO Board is to have no more than nine members.

The AESO Board is responsible for overseeing the business and affairs of the AESO. The AESO Board is actively involved in the strategic planning process and discusses and reviews all materials relating to the strategic plan with management. At least one Board meeting per year is devoted to discussing and considering the strategic plan, which takes into account the risks and opportunities of the AESO.

The AESO Board has two standing committees:

- The Audit Committee reviews and monitors the financial reporting process, the system of internal controls, the systems for managing risk, the external audit process and the AESO’s process for monitoring compliance with laws and regulations, with a view to ensuring best practices are followed.

- The Human Resources Committee provides advice and recommendations to the AESO Board on executive compensation levels, chief executive officer performance, officer selection, and human resources programs (including salary planning and incentive design), and shares information on current human resources practices.

Each AESO Board committee operates in accordance with a charter that has been approved by the full AESO Board.
2. SUMMARY ANNUAL HIGHLIGHTS

The AESO, a not-for-profit statutory corporation, recovers its operating and capital costs through three separate revenue sources, each of which is designed to recover the costs directly related to the provision of a specific service, as well as a portion of the shared corporate service costs. The overall revenues and costs of the AESO are as follows:

<table>
<thead>
<tr>
<th>(Millions)</th>
<th>Years ended December 31</th>
<th>2005</th>
<th>2004</th>
<th>Variance</th>
<th>% Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission revenue</td>
<td>$ 845.6</td>
<td>$ 662.3</td>
<td>$ 183.3</td>
<td>28</td>
<td></td>
</tr>
<tr>
<td>Energy market charge</td>
<td>12.6</td>
<td>12.2</td>
<td>0.4</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>Load settlement</td>
<td>2.7</td>
<td>1.9</td>
<td>0.8</td>
<td>42</td>
<td></td>
</tr>
<tr>
<td>Interest and other income</td>
<td>1.2</td>
<td>0.6</td>
<td>0.6</td>
<td>100</td>
<td></td>
</tr>
<tr>
<td>Wire costs</td>
<td>$ 420.0</td>
<td>$ 398.1</td>
<td>$ 21.9</td>
<td>6</td>
<td></td>
</tr>
<tr>
<td>Ancillary services</td>
<td>189.8</td>
<td>123.0</td>
<td>66.8</td>
<td>54</td>
<td></td>
</tr>
<tr>
<td>Line losses</td>
<td>200.8</td>
<td>109.1</td>
<td>91.7</td>
<td>84</td>
<td></td>
</tr>
<tr>
<td>General and administrative</td>
<td>38.6</td>
<td>35.9</td>
<td>2.7</td>
<td>8</td>
<td></td>
</tr>
<tr>
<td>Amortization and depreciation</td>
<td>6.6</td>
<td>5.6</td>
<td>1.0</td>
<td>18</td>
<td></td>
</tr>
<tr>
<td>Other industry costs</td>
<td>5.3</td>
<td>5.0</td>
<td>0.3</td>
<td>6</td>
<td></td>
</tr>
<tr>
<td>Interest expense</td>
<td>1.0</td>
<td>0.7</td>
<td>0.3</td>
<td>43</td>
<td></td>
</tr>
</tbody>
</table>

3. REVENUE

The Electric Utilities Act (EUA) requires that the AESO be operated so that no profit or loss results on an annual basis from its operations. To achieve this, revenue is recognized to the extent of annual operating costs, including the depreciation of capital assets. When the annual sum of collections differs from the annual operating costs, the difference is recorded as revenue or deferred revenue and recognized in the deferral accounts. The AESO's three revenue sources are the following:

Transmission

**Revenue Summary**

<table>
<thead>
<tr>
<th>(Millions)</th>
<th>Years ended December 31</th>
<th>2005</th>
<th>2004</th>
<th>Variance</th>
<th>% Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission revenue</td>
<td>$ 845.6</td>
<td>$ 662.3</td>
<td>$ 183.3</td>
<td>28</td>
<td></td>
</tr>
<tr>
<td>Interest and other revenue</td>
<td>0.8</td>
<td>0.0</td>
<td>0.8</td>
<td>100</td>
<td></td>
</tr>
<tr>
<td>Total transmission revenue</td>
<td>$ 846.4</td>
<td>$ 662.3</td>
<td>$ 184.1</td>
<td>28</td>
<td></td>
</tr>
</tbody>
</table>

The AESO is responsible for paying all of the costs of managing the provincial transmission system and recovering the costs through a tariff approved by the Alberta Energy and Utilities Board (EUB). The tariff is designed to allocate the costs to all users of the transmission system based upon their level of usage.

On a monthly basis, the AESO invoices its transmission customers for transmission system access services based upon approved tariff rates. The AESO also pays for costs associated with providing system access services. The monthly differences in the revenues collected and the costs incurred are accumulated in the AESO’s transmission deferral account and can be attributed to several factors:

- the timing of revenues and costs (monthly fluctuations)
- unanticipated forecast changes (pool price volatility, meter volumes and regulatory decisions)
- any misalignment of approved rates and the current year revenue requirement (delays in having the current year rates approved)
In circumstances where collections are in excess of the transmission costs, the excess amount is recorded as deferred revenue, recognized in the deferral accounts and refunded to customers in future periods. In circumstances where collections are less than the transmission costs, the shortfall is recorded as revenue, recognized in the deferral accounts and recovered from transmission customers in future periods.

As part of the transmission tariff, Rate Rider C is intended to bring the transmission deferral account balance to zero during the following calendar quarter. It is a dollar per megawatt hour collection or payment by rate class and rate component.

On an annual basis, the AESO files a retrospective deferral account reconciliation application with the EUB for approval of the final settlement amounts. The final reconciliation process associates all revenue and cost adjustments by rate category to the appropriate production month and allocates the corresponding charges and refunds to transmission customers.

The interest revenue in 2005 of $0.8 million relates to the interest earned on transmission customer security deposits, customer contribution funds held by the AESO awaiting transmission facility owner (TFO) billings and transmission deferral funds held awaiting the annual deferral account reconciliation for years prior to 2005. Given the nature of these deposits, interest revenue is a non-recurring item.

**Deferral Summary**

<table>
<thead>
<tr>
<th>(Millions) Years ended December 31</th>
<th>2005</th>
<th>2004</th>
</tr>
</thead>
<tbody>
<tr>
<td>Collections</td>
<td>$827.6</td>
<td>$733.1</td>
</tr>
<tr>
<td>Costs</td>
<td>846.4</td>
<td>662.3</td>
</tr>
<tr>
<td>Transmission (revenue) deferred revenue</td>
<td>(18.8)</td>
<td>70.8</td>
</tr>
<tr>
<td>Deferral account payable (receivable), beginning of year</td>
<td>30.1</td>
<td>(40.2)</td>
</tr>
<tr>
<td>2004 re-allocation adjustment</td>
<td></td>
<td>(0.5 )</td>
</tr>
<tr>
<td>Deferral account payable, end of year</td>
<td>$11.3</td>
<td>$30.1</td>
</tr>
</tbody>
</table>

On an annual basis, transmission collections are dependent upon approved transmission tariff rates, pool price and volumes of energy transmitted. Transmission costs are discussed in the following section.

As a result of a shortfall in 2005 collections, the transmission deferral account at Dec. 31, 2005 is $11.3 million payable to transmission customers, compared to $30.1 million payable to transmission customers at the end of 2004.

The transmission deferral balance of $11.3 million at Dec. 31, 2005 is comprised of three components:

- The net revenue and cost adjustments of $17.1 million payable to transmission customers that relate to production years prior to 2005, which have accumulated since the AESO filed the 2003 deferral account reconciliation in the latter part of 2004. These new adjustments will be settled with the filing of the retrospective deferral account applications.
- The variance in revenues collected and costs incurred in 2005 for the current year production have contributed to a transmission deferral account balance of $4.7 million receivable. The 2006 first quarter Rate Rider C charge and refund have been set to bring the deferral account balance to zero for the 2005 related production amounts.
- The remaining transmission customer receivable of $1.1 million is the deferred rent related to the amortization of a 10 month rent-free period on the AESO’s current office lease. This amortization of rent is not incorporated into the AESO’s annual revenue requirement, which includes only the cash payments.
Energy Market

Revenue Summary

(Millions) Years ended December 31

<table>
<thead>
<tr>
<th></th>
<th>2005</th>
<th>2004</th>
<th>Variance</th>
<th>% Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy market revenue</td>
<td>$12.6</td>
<td>$12.2</td>
<td>$0.4</td>
<td>3%</td>
</tr>
<tr>
<td>Interest and other revenue</td>
<td>0.4</td>
<td>0.6</td>
<td>(0.2)</td>
<td>(33%)</td>
</tr>
<tr>
<td>Total energy market revenue</td>
<td>$13.0</td>
<td>$12.8</td>
<td>$0.2</td>
<td>2%</td>
</tr>
</tbody>
</table>

The AESO recovers the costs of operating the real-time energy market through an energy market trading charge on all megawatt hours traded. The energy market trading charge for a period is set to recover the operating costs and the depreciation of capital assets during that period.

In circumstances where annual collections are in excess of energy market costs, the excess amount is recorded as deferred revenue, recognized in the deferral accounts and incorporated into a reduction in the following year’s required energy market trading charge. In circumstances where annual collections are less than the energy market costs, the shortfall is recorded as revenue, recognized in the deferral accounts and collected in the following year.

The energy market deferral amount is comprised of two components:

- The accumulated difference between revenues collected and costs paid that is receivable from, or payable to, energy market participants.
- The unamortized portion of AESO’s system controller capital assets that were recovered from transmission customers in prior years by the Transmission Administrator of Alberta Ltd. (TA). The revenue associated with the system controller capital assets is recognized by the AESO over the useful life of the assets. These assets will be fully depreciated in 2008.

Energy market collections are dependent upon the annual energy market trading charge and the volume of energy traded through the power pool. For the second consecutive year, the energy market trading charge was 11.1 cents per megawatt hour traded.

Deferral Summary

(Millions) Years ended December 31

<table>
<thead>
<tr>
<th></th>
<th>2005</th>
<th>2004</th>
</tr>
</thead>
<tbody>
<tr>
<td>Collections</td>
<td>$13.2</td>
<td>$13.3</td>
</tr>
<tr>
<td>Costs</td>
<td>13.0</td>
<td>12.8</td>
</tr>
<tr>
<td>Energy market deferred revenue</td>
<td>0.2</td>
<td>0.5</td>
</tr>
<tr>
<td>Deferral account payable, beginning of year</td>
<td>5.8</td>
<td>4.8</td>
</tr>
<tr>
<td>2004 re-allocation adjustment</td>
<td>–</td>
<td>0.5</td>
</tr>
<tr>
<td>Deferral account payable, end of year</td>
<td>$6.0</td>
<td>$5.8</td>
</tr>
</tbody>
</table>

The energy market deferral amount at Dec. 31, 2005 is $6.0 million payable compared to $5.8 million payable at the end of 2004. The increase of $0.2 million during 2005 was a result of:

- surplus collections in energy market trading charges of $1.1 million; offset by
- depreciation of system controller capital assets of $0.9 million.
Of the Dec. 31, 2005 deferral surplus of $6.0 million, $5.1 million is payable to energy market participants and is incorporated into the trading charge requirements for 2006. The remaining deferral balance of $0.9 million relates to the system controller capital assets to be depreciated in future years.

A portion of the energy market charged collected by the AESO is remitted to the Market Surveillance Administrator (MSA) for its revenue requirement in accordance with the EUA. The AESO facilitates the cash collection process for the funding of the MSA through a per megawatt hour addition to the AESO’s energy market trading charge. In 2005, the MSA’s portion of the total energy market trading charge of 13.4 cents per megawatt hour was 2.3 cents per megawatt hour, with the remaining 11.1 cents per megawatt hour for the AESO’s operations. This compares to a MSA charge of 2.5 cents per megawatt hour in 2004.

The MSA’s revenue and costs are separate and independent of the AESO’s financial records. The AESO records the difference between the payments made to the MSA and the collection on behalf of the MSA as a separate deferral account. At Dec. 1, 2005 there was a $0.2 million surplus in MSA collections, unchanged from the balance at Dec. 31, 2004.

### Load Settlement

#### Revenue Summary

<table>
<thead>
<tr>
<th>(Millions) Years ended December 31</th>
<th>2005</th>
<th>2004</th>
<th>Variance</th>
<th>% Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Load settlement recovery</td>
<td>$ 2.7</td>
<td>$ 1.9</td>
<td>$ 0.8</td>
<td>42%</td>
</tr>
<tr>
<td>Interest and other revenue</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0%</td>
</tr>
<tr>
<td>Total load settlement revenue</td>
<td>$ 2.7</td>
<td>$ 1.9</td>
<td>$ 0.8</td>
<td>42%</td>
</tr>
</tbody>
</table>

The expenses that are incurred by the AESO to provide services related to administering and regulating provincial load settlement are charged to the owners of electric distribution systems and wire service providers conducting load settlement under the AESO’s Independent System Operator (ISO) rules. The costs associated with load settlement include direct function costs, an allocation of the AESO corporate shared services and an allocation of depreciation for the recovery of capital acquisitions.

The difference in the annual revenue collections and costs incurred associated with load settlement is recorded in the deferral accounts. On an annual basis, the load settlement deferral amount is charged or refunded to the owners of electric distribution systems and wire service providers.

### Deferral Summary

<table>
<thead>
<tr>
<th>(Millions) Years ended December 31</th>
<th>2005</th>
<th>2004</th>
</tr>
</thead>
<tbody>
<tr>
<td>Collections</td>
<td>$ 1.7</td>
<td>$ 2.7</td>
</tr>
<tr>
<td>Costs</td>
<td>2.7</td>
<td>1.9</td>
</tr>
<tr>
<td>Load settlement (revenue) deferred revenue</td>
<td>(1.0)</td>
<td>0.8</td>
</tr>
<tr>
<td>Deferral account payable, beginning of year</td>
<td>0.8</td>
<td>0.0</td>
</tr>
<tr>
<td>Deferral account (receivable) payable, end of year</td>
<td>$ (0.2)</td>
<td>$ 0.8</td>
</tr>
</tbody>
</table>

Load settlement collections are dependent upon the AESO’s annual forecast of load settlement costs. In 2004, the anticipated cost increases did not occur resulting in a $0.8 million overcollection. This amount was incorporated into the 2005 collections.
4. OPERATING COSTS

Transmission System Costs
The following information provides the costs of managing the transmission system. These amounts represent the recording of the financial transactions that occurred in the reporting periods. This differs from the production period reporting in the AESO’s General Tariff Applications.

<table>
<thead>
<tr>
<th>(Millions) Years ended December 31</th>
<th>2005</th>
<th>2004</th>
<th>Variance</th>
<th>% Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wire costs</td>
<td>$ 420.0</td>
<td>$ 398.1</td>
<td>$ 21.9</td>
<td>6</td>
</tr>
<tr>
<td>Line losses</td>
<td>$ 200.8</td>
<td>$ 109.1</td>
<td>$ 91.7</td>
<td>84</td>
</tr>
<tr>
<td>Ancillary services costs</td>
<td>$ 189.8</td>
<td>$ 123.0</td>
<td>$ 66.8</td>
<td>54</td>
</tr>
<tr>
<td>Other industry costs</td>
<td>$ 5.3</td>
<td>$ 5.0</td>
<td>$ 0.3</td>
<td>6</td>
</tr>
</tbody>
</table>

Wires Costs
Wires costs represent the amount paid to the owners of the transmission facilities in accordance with their EUB-approved tariffs and are not controllable costs of the AESO. The costs increased $21.9 million or six per cent compared to 2004 due to changes in the regulated rates charged by the transmission facility owners.

Line Losses
Line losses represent the amount of energy that is ‘lost’ as a result of electrical resistance on the transmission lines. The volumes associated with line losses are determined through the energy market settlement as the difference between the generation and import volumes less consumption and export volumes. The hourly volumes of line losses are affected by short- and long-term outages of equipment due to maintenance and unexpected failures, and dispatch decisions on the Alberta Interconnected Electric System (AIES). The value of line losses is calculated at the hourly pool price.

To prepare an appropriate year-over-year comparison of transmission line losses, $37.1 million in prior year adjustments must be added back to the 2004 line losses of $109.1 million, resulting in 2004 production-year line losses of $146.2 million. After this adjustment, the cost of line losses in 2005 is $200.8 million compared to $146.2 million in 2004, an increase of $54.6 million or 37 per cent.

In 2005, the volume of line losses remained unchanged from 2004 at approximately 2.9 terawatt hours annually.

The 2005 annual average pool price, at which losses are valued, increased by approximately 30 per cent from 2004 ($70 per megawatt hour from $55 per megawatt hour) causing line loss costs to increase 37 per cent. The disproportionate increase in costs compared to pool price is caused by the hourly variance in loss volumes and the associated hourly pool price. System losses generally increase as system load increases, which typically coincides with increases to the hourly pool price. Consequently, the cost of losses will increase disproportionately in that hour in comparison to monthly or annual averages.

Ancillary Services
Ancillary services are procured by the AESO to ensure ongoing reliability of the transmission system through contracts, which may be exchange traded or over-the-counter contracts, for generation capacity and for load reduction capabilities. The AESO has entered into various contracts for ancillary services that include operating reserves, transmission must-run, under-frequency mitigation and system restoration.

The cost of ancillary services increased to $189.8 million in 2005 compared to $123.0 million in 2004, an increase of $66.8 million or 54 per cent. This increase is mainly due to the changes in costs associated with operating reserves and transmission must-run services as described on the following page.
**Operating Reserves** are comprised of three types of active reserves, with the minimum levels of operating reserves established by the Western Electricity Coordinating Council (WECC):

- **Regulating reserves** — The provision of generation and load response capability, including capacity, energy and maneuverability, which respond to automatic generator controls (AGC) issued by the AESO’s system controller.
- **Spinning reserves** — Unloaded generation that is synchronized to the system, automatically responsive to frequency deviation and ready to serve additional demand following an AESO system controller directive. A customer offering spinning reserves must be able to ramp the generator up within 10 minutes in response to a system controller directive due to a system contingency.
- **Supplemental reserves** — Similar to spinning reserves except supplemental reserves are not required to respond to frequency deviations; therefore, they include load and generators.

Operating reserves are purchased from the ancillary services market exchange and through over-the-counter contracts. All operating reserve providers are paid their accepted offer price for the ability of the AESO to utilize their energy as reserves. The majority of operating reserve offer prices are indexed to the pool price.

Operating reserves costs increased to $122.3 million in 2005 compared to $69.2 million in 2004, an increase of $53.1 million or 77 per cent. There are two primary factors contributing to the overall cost increase.

For active regulating and spinning reserves, while reserve volumes remained comparable to 2004, a $31.8 million increase in costs in 2005 is attributable to the general increases in pool price relative to 2004. Most notable were the fourth quarter 2005 monthly pool prices, which averaged $117 per megawatt hour compared to $55 per megawatt hour in the same period in 2004, a 112 per cent increase. Accordingly, this change in the fourth quarter pool price contributed to a $23.6 million increase in operating reserves costs compared to the same period in 2004.

The second factor contributing to the increase in operating reserves is the cost of active supplemental reserves. In August 2004, the contract for offering hydro power purchase arrangement energy was amended, which subsequently resulted in higher supplemental reserves costs. This pricing adjustment as well as the increase in the average pool price in 2005 resulted in a $19.7 million or 176 per cent increase in supplemental reserves in 2005, an increase from $11.2 million in 2004 to $30.9 million in 2005.

**Transmission Must-run (TMR)** is generation required to be on-line and running at specific outputs in certain parts of the AES to ensure system reliability. This service is typically procured through commercial contracts between the AESO and suppliers.

The costs of TMR are dependent upon numerous variables including, but not limited to, market heat rates and gas prices. The market heat rate is the pool price divided by the gas price. As the market heat rate increases, representing a divergence of pool price and gas price, the cost of TMR contracts will decrease, though not proportionately. With gas price increases, the costs of TMR will generally increase.

TMR costs increased to $56.4 million in 2005 compared to $43.1 million in 2004, an increase of $13.3 million or 31 per cent. Contributing to the increase are changes that occurred with market heat rates and gas prices. In 2005, the market heat rate and average gas price were $8.49 and $8.28 per gigajoule respectively compared to $8.83 and $6.17 in 2004. This represents a four per cent decrease in the market heat rate and a 34 per cent increase in the average gas price, compounded to contribute to the overall increase in TMR costs. In addition, the AESO incurred a one-time cost in 2005 to postpone the decommissioning of the Rossdale generation facility; this facility has been contracted to provide TMR services on a short-term basis.
Other Industry Costs
Other industry costs represent certain costs the AESO funds on behalf of industry participants, including the costs of stakeholder participation in the AESO's regulatory proceedings, the cost of membership in the WECC and an allocation for EUB-related costs.

Other industry costs increased marginally in 2005, a six per cent or $0.3 million increase from $5.0 million in 2004 to $5.3 million in 2005.

General and Administrative Costs
The following table presents the general and administrative costs for the AESO:

<table>
<thead>
<tr>
<th>(Millions) Years ended December 31</th>
<th>2005</th>
<th>2004</th>
<th>Variance</th>
<th>% Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Salaries and benefits</td>
<td>$26.8</td>
<td>$22.8</td>
<td>$4.0</td>
<td>18</td>
</tr>
<tr>
<td>Professional fees and consulting</td>
<td>4.5</td>
<td>5.2</td>
<td>(0.7)</td>
<td>(13)</td>
</tr>
<tr>
<td>Office and administrative</td>
<td>7.3</td>
<td>7.9</td>
<td>(0.6)</td>
<td>(8)</td>
</tr>
<tr>
<td>Total general and administrative</td>
<td>38.6</td>
<td>35.9</td>
<td>2.7</td>
<td>8</td>
</tr>
<tr>
<td>Amortization and depreciation</td>
<td>6.6</td>
<td>5.6</td>
<td>1.0</td>
<td>18</td>
</tr>
<tr>
<td>Interest</td>
<td>1.0</td>
<td>0.7</td>
<td>0.3</td>
<td>43</td>
</tr>
<tr>
<td>Total general and administrative</td>
<td>$46.2</td>
<td>$42.2</td>
<td>$4.0</td>
<td>9</td>
</tr>
</tbody>
</table>

Salary and Benefits
The increase is due to a full year’s salary and benefits for staff hired in 2004, staff hired during 2005 and annual performance adjustments for staff. In addition, corporate reorganization costs were incurred in 2005 that are non-recurring costs.

Professional Fees and Consulting
Consultants are required to supplement staff during peak work requirements and provide technical expertise. In 2004, the most notable consulting costs were incurred to provide support for regulatory activities and to complete process efficiency initiatives that began with the 2003 corporate merger. Consulting activities in 2005 focused on transmission-related initiatives and IT technical support.

Office and Administrative
The decrease in 2005 is mainly attributable to lease and lease related costs. In 2004, the AESO leased new office space and additional costs were incurred for overlapping lease space during the office relocation and for the time period that the vacated office space was unoccupied while sub-tenancy was arranged. In 2005, the office and administrative costs were offset by sub-tenant payments.

Amortization and Depreciation
Depreciation of capital assets in 2005 includes the first full year of depreciation for the 2004 additions, new additions in 2005 offset by a reduction in depreciation for assets that became fully depreciated in 2005. Capital expenditures in 2005 were $13.0 million, of which $3.4 million are work-in-progress assets that are not yet subject to depreciation.
Interest
Interest expense is incurred as a result of the bank debt held throughout the year. Interest costs are incurred to fund capital purchases and working capital due to the timing differences in the collection of revenues and the payment of expenses. Contributing to the increase in interest expense in 2005 is a higher net book value of the capital assets, which are debt financed until the assets are fully depreciated. The net book value of capital assets was $22.5 million at the end of 2004 compared to $28.8 million in 2005.

5. FUNCTIONAL COST DETAIL
The AESO has been organized to integrate the functions of transmission, energy market and load settlement to maximize the benefits under the EUA. This integration results in cost allocations in many parts of the organization for the purpose of cost recovery. Management views the operations as one fully integrated operation. In determining the revenue requirement on a function-by-function basis, all AESO costs are assigned or allocated to one of the three functions.

<table>
<thead>
<tr>
<th>(Millions)</th>
<th>General and Administrative</th>
<th>Amortization and Depreciation</th>
<th>Interest</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission</td>
<td>$ 27.8</td>
<td>$25.7</td>
<td>$2.3</td>
<td>$1.6</td>
</tr>
<tr>
<td>Energy market</td>
<td>8.7</td>
<td>8.5</td>
<td>3.9</td>
<td>3.9</td>
</tr>
<tr>
<td>Load settlement</td>
<td>2.1</td>
<td>1.7</td>
<td>0.4</td>
<td>0.1</td>
</tr>
<tr>
<td>Total</td>
<td>$38.6</td>
<td>$35.9</td>
<td>$6.6</td>
<td>$5.6</td>
</tr>
</tbody>
</table>

General and Administrative
The percentage allocation of costs by function are unchanged from 2004 for total general and administrative costs as a result of the consistent allocation percentages applied in 2005 and 2004.

Amortization and Depreciation
In 2005, the transmission and load settlement functions were allocated a greater share of the depreciation costs due to general corporate additions in 2005 that are recovered to a greater extent from the transmission function and the commissioning of the new load settlement compliance monitoring software application in November 2005. Energy market depreciation remained consistent with 2004 as a result of the offset between 2005 capital additions and completed depreciation on prior year assets.

Interest
Interest expense is incurred to fund capital purchases and working capital deficiencies. With the changes that occurred in 2005 to the function-level asset net book values and transmission working capital requirements, offset by an interest expense reduction for imputed interest income related to transmission settlement funds awaiting deferral account reconciliation, the allocation of interest costs changed in comparison to 2004.
6. **FINANCIAL POSITION AND LIQUIDITY**

(Millions) Year ended December 31

<table>
<thead>
<tr>
<th></th>
<th>2005</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cash, beginning of year</td>
<td>$14.7</td>
</tr>
<tr>
<td>Operating activities</td>
<td>31.6</td>
</tr>
<tr>
<td>Investing activities</td>
<td>(13.0)</td>
</tr>
<tr>
<td>Financing activities</td>
<td>(2.4)</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>16.2</td>
</tr>
<tr>
<td>Cash, end of year</td>
<td>$30.9</td>
</tr>
</tbody>
</table>

The cash balance as at Dec. 31, 2005 was $30.9 million compared to $14.7 million at Dec. 31, 2004. The increase is primarily the result of the following:

- **Operating activities** provided cash of $31.6 million in 2005. The increase is mainly attributed to a change in non-cash working capital of $25.0 million.
  - Accounts receivable balance at Dec. 31, 2005 was $108.4 million compared to $101.7 million at Dec. 31, 2004, an increase of $6.7 million. This increase relates to a $9.9 million increase in the transmission revenue accruals in 2005. The pool price is a key component in determining monthly transmission revenues. The change in the December monthly average pool price from $63 per megawatt hour in 2004 to $103 per megawatt hour in 2005, a $40 per megawatt hour or 63 per cent increase, is the main contributor to this increase.
  - Accounts payable balance at Dec. 31, 2005 was $113.8 million compared to $85.2 million at Dec. 31, 2004, an increase of $28.6 million. As with accounts receivable, the increase in the December monthly average pool price has also increased the transmission cost accruals by $17.0 million for costs indexed to the pool price. In addition, transmission customers’ capital contributions held by the AESO at year end increased by $10.0 million compared to December 2004.
  - Participants’ security deposits balance at Dec. 31, 2005 were $7.4 million compared to $4.3 million at Dec. 31, 2004, an increase of $3.1 million. The balance of security deposits held by the AESO is solely dependent on how participants elect to meet the AESO’s security requirements.

- **Investing activities** used cash of $13.0 million for capital asset additions.

- **Financing activities** used cash of $2.4 million in 2005. The primary financing activities were a reduction of the $18.8 million transmission deferral account payable to customers, which was offset by increased bank financing of $16.9 million.

As at Dec. 31, 2005, the AESO had the following credit lines available to fund general operating and capital activities:

(Millions) Year ended Dec. 31, 2005

<table>
<thead>
<tr>
<th></th>
<th>Total</th>
<th>Available</th>
<th>Used</th>
</tr>
</thead>
<tbody>
<tr>
<td>Term revolving facility</td>
<td>$50.0</td>
<td>$23.9</td>
<td>$26.1</td>
</tr>
<tr>
<td>Demand revolving facility</td>
<td>$40.0</td>
<td>$16.0</td>
<td>$24.0</td>
</tr>
<tr>
<td>Demand non-revolving facility</td>
<td>$20.0</td>
<td>$20.0</td>
<td>$0.0</td>
</tr>
<tr>
<td>Demand treasury risk management facility</td>
<td>$9.0</td>
<td>$9.0</td>
<td>$0.0</td>
</tr>
</tbody>
</table>

The term revolving facility includes a $20 million letter of credit at Dec. 31, 2005.
7. OUTLOOK

Cost recovery for the operations of the AESO is approved on an annual basis by the AESO Board, and for transmission-related activities, subsequently by the EUB.

For transmission-related activities in 2006, the AESO’s General Tariff Application revenue requirement has been approved for $725.0 million compared to $802.3 million in 2005. This revenue requirement includes costs related to wire, ancillary services, line losses, and other industry and general and administrative costs. This 10 per cent or $77.3 million decrease is primarily due to a forecasted reduction in wire and line losses costs in 2006.

The enactment of the Transmission Regulation by Alberta Energy in August 2004 set the direction for a number of transmission development issues in the province, one of which is the cost recovery mechanism for transmission-related costs through the AESO’s transmission tariff. This regulation requires the AESO to develop transmission rates effective Jan. 1, 2006 that allocate all costs of the transmission system (except for losses and regulated generating unit connection costs) to load customers and exporters. While this change in 2006 will not impact the overall transmission-related costs, it will impact the allocation of the costs for recovery purposes.

For energy market activities, the annual costs are forecasted to increase to $15.4 million in 2006 from the 2005 actual costs of $13.0 million, a $2.4 million or 18 per cent increase. This forecasted increase is a combination of anticipated cost increases for salaries and benefits, telecommunication and information technology areas and amortization and depreciation. With the combination of this forecasted cost increase and the 2005 deferral balance, the AESO’s portion of the 2006 energy market trading charge will remain unchanged from 2005 at 11.1 cents per megawatt hour. In 2006, the total energy market trading charge will be 12.9 cents per megawatt hour, a change from the 2005 charge of 13.4 cents per megawatt hour due to a decrease in the MSA’s charge.

With the commissioning of a new compliance monitoring software application in November 2005 and the related future recovery amounts, load settlement costs are forecasted to increase to $5.6 million in 2006 from the 2005 actual costs of $2.7 million. The recovery of the capital acquisition costs will occur over a five-year depreciation period.

In 2006, the AESO will begin occupancy of a newly constructed facility for the operations of the AESO’s system coordination centre. The facility will be a single-tenant, security focused location. The recovery of costs related to this capital expenditure will occur over the useful life of the facility, currently estimated at 20 years, through an allocation to transmission customers and energy market participants.

Continuing into 2006, the AESO will work with industry on the implementation of Alberta’s Electricity Policy Framework to provide refinements to the wholesale market structure. The costs related to this initiative are currently being assessed.

8. RISK MANAGEMENT

Similar to other electric system operators and wholesale market facilitators, the AESO is exposed to various risks and uncertainties in the normal course of business. The risk management processes developed by the AESO are designed to identify the risks confronting the AESO, assessing the impact and likelihood of those risks occurring, and determining mitigation strategies to be taken. Regular reports are provided to senior management and the Audit Committee detailing the status of the risks identified and the related mitigation strategies. The AESO prioritizes the risks identified and incorporates this information into the organization’s corporate strategies and annual goals and objectives.
While many of the risks identified by the AESO’s risk management processes are not directly within the control of the AESO, it has adopted several strategies to reduce and mitigate the effects of those risks identified that are within its control. The key features of the AESO’s internal control environment, which facilitate the AESO’s risk management processes are as follows:

- The AESO is governed by an independent Board, that is appointed by the Alberta Minister of Energy, and is independent from any person or entity having a material interest in the electricity industry.
- The AESO, the members of its independent Board and its employees are extended a degree of statutory liability protection consistent with the AESO’s public interest mandate.
- Corporate policies have been developed and are approved by the AESO Board. Corporate policies are communicated to employees regularly and are accessible by employees at all times.
- The Audit Committee reviews and monitors the system of internal controls, the systems for managing risk, the external audit process, and the AESO’s process for monitoring compliance with laws and regulations, with a view to ensuring best practices are followed.
- The AESO reports its significant risks to the Audit Committee on a regular basis and provides updates on the implementation of mitigation strategies that are undertaken.
- The AESO’s management, led by the President and Chief Executive Officer, is committed to maintaining the highest level of ethics and integrity. Management endeavours to foster this culture throughout the organization.
- The AESO Code of Conduct serves as a framework for AESO officers, employees and contractors of the AESO faced with difficult situations where laws and regulations are not enough to assist the employee. Employees are required to indicate their compliance with the Code of Conduct on at least an annual basis.
- Risk assessment is a continuous process undertaken by management. The AESO management is committed to proactively addressing potential risks identified and implementing appropriate mitigation action plans.
- The AESO management and supervisory personnel monitor the quality of internal control performance as a normal part of their activities. Monitoring is performed over a wide variety of functions at all levels across the organization and occurs through the use of both automated and manual processes.
- The AESO carries insurance coverage that is deemed to be appropriate by management. The insurance coverage may not be adequate to cover all possible risks and the proceeds of any insurance claim may not be adequate to cover all potential losses.

9. FORWARD-LOOKING STATEMENTS

This MD&A contains forward-looking statements that are subject to certain assumptions and risks that create uncertainties. These assumptions and risks could cause actual results to differ materially from results anticipated by the forward-looking statements.

10. ADDITIONAL INFORMATION

Additional information relating to the AESO can be found on the corporate website at www.aeso.ca.
Management’s Responsibility for Financial Reporting

The financial statements included in the annual report are the responsibility of management and have been approved by the Alberta Electric System Operator Board. These financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles, and include the use of estimates and assumptions that have been made using management’s best judgment. Financial information contained elsewhere in this annual report is consistent with that in the financial statements.

To discharge its responsibility for financial reporting, management maintains a system of internal controls designed to provide reasonable assurance that the Alberta Electric System Operator’s assets are safeguarded, that transactions are properly authorized and that financial information is relevant, accurate and available on a timely basis.

The financial statements have been examined by Deloitte & Touche LLP, the Alberta Electric System Operator’s external independent auditors. The responsibility of these external auditors is to examine the financial statements and to express their opinion on the fairness of the financial statements in accordance with Canadian generally accepted accounting principles. The auditors’ report outlines the scope of their examination and states their opinion.

M. Dale McMaster, P.Eng.
President and Chief Executive Officer

David Erickson, CA
Senior Vice-President and Chief Financial Officer
To the Members of the Alberta Electric System Operator Board

We have audited the balance sheets of the Alberta Electric System Operator as at December 31, 2005 and 2004 and the statement of operations and cash flows for the years then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Chartered Accountants
Calgary, Alberta
January 30, 2006
# Balance Sheet

As at December 31 (in thousands of Canadian dollars)

<table>
<thead>
<tr>
<th></th>
<th>2005</th>
<th>2004</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Assets</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current assets</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cash</td>
<td>$30,938</td>
<td>$14,670</td>
</tr>
<tr>
<td>Accounts receivable</td>
<td>108,383</td>
<td>101,711</td>
</tr>
<tr>
<td>Prepaid expenses and deposits</td>
<td>2,026</td>
<td>1,963</td>
</tr>
<tr>
<td></td>
<td><strong>141,347</strong></td>
<td><strong>118,344</strong></td>
</tr>
<tr>
<td>Capital assets (note 5)</td>
<td>28,785</td>
<td>22,465</td>
</tr>
<tr>
<td></td>
<td><strong>170,132</strong></td>
<td><strong>140,809</strong></td>
</tr>
<tr>
<td><strong>Liabilities</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current liabilities</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Accounts payable and accrued liabilities (note 6)</td>
<td>$113,829</td>
<td>$85,189</td>
</tr>
<tr>
<td>AESO deferral accounts payable (note 4)</td>
<td>16,902</td>
<td>35,745</td>
</tr>
<tr>
<td>MSA deferral account payable</td>
<td>177</td>
<td>181</td>
</tr>
<tr>
<td>Participants’ security deposits (note 10)</td>
<td>7,438</td>
<td>4,329</td>
</tr>
<tr>
<td>Bank debt (note 7)</td>
<td>30,100</td>
<td>13,200</td>
</tr>
<tr>
<td></td>
<td>168,446</td>
<td>138,644</td>
</tr>
<tr>
<td>Deferred rent</td>
<td>1,465</td>
<td>1,226</td>
</tr>
<tr>
<td>Long-term AESO deferral accounts payable (note 4)</td>
<td>221</td>
<td>939</td>
</tr>
<tr>
<td><strong>Equity</strong> (note 1)</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td></td>
<td><strong>170,132</strong></td>
<td><strong>140,809</strong></td>
</tr>
</tbody>
</table>

Contingencies and commitments (note 9)

On behalf of the AESO Board:

F. Maury Parsons  
AESO Board Chair

Robert McKenzie  
AESO Board Member
Statement of Operations

For the Year Ended December 31 (in thousands of Canadian dollars)

<table>
<thead>
<tr>
<th></th>
<th>2005</th>
<th>2004</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Revenue</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Transmission revenue</td>
<td>845,610</td>
<td>662,261</td>
</tr>
<tr>
<td>Energy market charge</td>
<td>12,641</td>
<td>12,225</td>
</tr>
<tr>
<td>Load settlement recovery</td>
<td>2,742</td>
<td>1,881</td>
</tr>
<tr>
<td>Interest and other</td>
<td>1,152</td>
<td>594</td>
</tr>
<tr>
<td><strong>Total Revenue</strong></td>
<td>862,145</td>
<td>676,961</td>
</tr>
<tr>
<td><strong>Operating costs and expenses</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wire costs</td>
<td>420,028</td>
<td>398,089</td>
</tr>
<tr>
<td>Line losses</td>
<td>200,789</td>
<td>109,149</td>
</tr>
<tr>
<td>Ancillary services costs (note 8)</td>
<td>189,741</td>
<td>123,020</td>
</tr>
<tr>
<td>General and administrative</td>
<td>38,632</td>
<td>35,908</td>
</tr>
<tr>
<td>Amortization and depreciation (note 5)</td>
<td>6,631</td>
<td>5,569</td>
</tr>
<tr>
<td>Other industry costs</td>
<td>5,344</td>
<td>4,961</td>
</tr>
<tr>
<td>Interest expense (note 7)</td>
<td>980</td>
<td>677</td>
</tr>
<tr>
<td><strong>Total Operating Costs and Expenses</strong></td>
<td>862,145</td>
<td>677,373</td>
</tr>
<tr>
<td><strong>Income before taxes</strong></td>
<td>–</td>
<td>(412)</td>
</tr>
<tr>
<td>Current income tax recovery</td>
<td>–</td>
<td>412</td>
</tr>
<tr>
<td><strong>Net income</strong></td>
<td>$ –</td>
<td>$ –</td>
</tr>
</tbody>
</table>
**Statement of Cash Flows**

For the Year Ended December 31 (in thousands of Canadian dollars)

<table>
<thead>
<tr>
<th></th>
<th>2005</th>
<th>2004</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Operating activities</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net income</td>
<td>$—</td>
<td>$—</td>
</tr>
<tr>
<td>Amortization and depreciation</td>
<td>6,631</td>
<td>5,569</td>
</tr>
<tr>
<td>Cash flows from operations</td>
<td>6,631</td>
<td>5,569</td>
</tr>
<tr>
<td>Changes in non-cash working capital*</td>
<td>25,014</td>
<td>(142,269)</td>
</tr>
<tr>
<td>Net cash provided by (used in) operating activities</td>
<td>31,645</td>
<td>(136,700)</td>
</tr>
<tr>
<td><strong>Investing activities</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capital asset additions</td>
<td>(12,951)</td>
<td>(11,542)</td>
</tr>
<tr>
<td>Net cash used in investing activities</td>
<td>(12,951)</td>
<td>(11,542)</td>
</tr>
<tr>
<td><strong>Financing activities</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Increase (decrease) in bank debt</td>
<td>16,900</td>
<td>(31,700)</td>
</tr>
<tr>
<td>Increase in deferred rent</td>
<td>239</td>
<td>1,226</td>
</tr>
<tr>
<td>(Decrease) increase in AESO deferral accounts</td>
<td>(19,561)</td>
<td>71,993</td>
</tr>
<tr>
<td>(Decrease) increase in MSA deferral account</td>
<td>(4)</td>
<td>746</td>
</tr>
<tr>
<td>Net cash (used in) provided by financing activities</td>
<td>(2,426)</td>
<td>42,265</td>
</tr>
<tr>
<td><strong>Increase (decrease) in cash</strong></td>
<td>16,268</td>
<td>(105,977)</td>
</tr>
<tr>
<td><strong>Cash, beginning of year</strong></td>
<td>14,670</td>
<td>120,647</td>
</tr>
<tr>
<td><strong>Cash, end of year</strong></td>
<td>$30,938</td>
<td>$14,670</td>
</tr>
</tbody>
</table>

* Consists of changes in accounts receivable, prepaid expenses and deposits, accounts payable and accrued liabilities and participants’ security deposits.
Notes to the Financial Statements

Dec. 31, 2005 and 2004
(All amounts are in thousands of Canadian dollars unless otherwise indicated)

NOTE 1. NATURE OF OPERATIONS

The Independent System Operator (ISO), operating as the Alberta Electric System Operator (AESO), is a statutory corporation established on June 1, 2003 under the Electric Utilities Act (EUA) of the Province of Alberta.

Effective June 1, 2003, the AESO assumed responsibility for the operation of the competitive power pool; determining the order of dispatch of electric energy and ancillary services; providing system access service on the electric transmission grid; directing the safe, reliable and economic operation of the interconnected electric system; planning the capability of the transmission system to meet future needs; and regulating and administering load settlement.

The AESO is governed by the AESO Board, whose members are appointed by the Alberta Minister of Energy and are independent of any person or entity having a material interest in the Alberta electric industry. The AESO Board has an Audit Committee and a Human Resources Committee.

The EUA requires that charges to industry, including the transmission tariff, energy market charge and load settlement charge, be set to recover the costs required to operate the AESO, and that the AESO be operated so no profit or loss results on an annual basis from its operations. The AESO has no equity.

Management views the operations as one fully-integrated operation; therefore, segmented information is not applicable.

NOTE 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared by management on the historical cost basis in accordance with Canadian generally accepted accounting principles. Preparation of these financial statements requires estimates and assumptions that affect the amounts reported and disclosed in the financial statements and related notes. These estimates and assumptions include information, regulatory decisions and other matters that are periodically influenced by third parties that may impact the timing of revenue and/or expense recognition. Any changes from current estimates or assumptions are accounted for in the period that they are determined. Actual results could differ from those estimates.
Deferrals

The AESO utilizes deferral accounts to facilitate a matching of revenues and costs. On an individual basis for the transmission, energy market and load settlement operations, in circumstances where annual collections are in excess of the costs, the excess amount is recorded as deferred revenue, recognized in the deferral accounts and refunded in the subsequent year. In circumstances where annual collections are less than the costs, the shortfall is recorded as revenue, recognized in the deferral accounts and collected in the subsequent year. The long-term AESO deferral balance relates to the energy market deferral for the unamortized portion of system controller capital assets that were recovered from transmission customers in prior years by the Transmission Administrator of Alberta (TA).

A portion of the energy market charge collected by the AESO is remitted to the Market Surveillance Administrator (MSA), a separate statutory corporation, according to its revenue requirement as provided in the EUA. When the annual revenue collected on behalf of the MSA through the energy market charge collection process is in excess of the funding payments made to the MSA, the excess is recorded as deferred revenue and is incorporated into the estimated per MWh charge for the following year. In circumstances where annual collections are less than the MSA payments, the shortfall is incorporated into the estimated per MWh charge for the following year.

Capital Assets

Capital assets are stated at cost. These assets are amortized on a straight-line basis over their estimated useful life as follows:

<table>
<thead>
<tr>
<th>Asset</th>
<th>Life</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy trading system</td>
<td>8 years</td>
</tr>
<tr>
<td>System coordination centre</td>
<td>8 years</td>
</tr>
<tr>
<td>Software development</td>
<td>5 years</td>
</tr>
<tr>
<td>Computer hardware, furniture and office equipment</td>
<td>3 years</td>
</tr>
<tr>
<td>Leasehold improvements</td>
<td>Over the lease term ending in 2014</td>
</tr>
</tbody>
</table>

Beginning in 2005, interest costs attributable to and incurred during the development phase of large capital projects are capitalized. Capitalization ceases when the projects are substantially complete and ready for productive use. Beginning in 2005, payroll and payroll related costs associated with staff directly involved in software development are capitalized. No adjustments to prior periods are applicable or required as a result of this policy adopted in 2005.

Revenue Recognition

The AESO’s revenue is primarily derived through three separate charges: (1) the transmission revenue; (2) the energy market charge; and (3) the load settlement recovery. Each of these charges is set to recover those costs directly attributable to one of the AESO’s main functions as well as a portion of shared corporate costs. Consistent with the requirements of the EUA, which requires the AESO to operate with no annual profit or loss, revenue is recognized equivalent to the aggregate of annual operating costs on a function-by-function basis.

The EUA requires the AESO to provide funding for the MSA with the amount to be recovered through the energy market charge. The energy market charge included in the AESO’s statement of operations does not include amounts recovered related to the MSA’s funding requirements and the AESO’s costs do not include amounts related to the operations of the MSA. The difference in the revenue collections and the monthly payments associated with the MSA are recorded in the MSA deferral account.
Deferred Rent
The AESO utilizes a deferred rent account to amortize the 10 month rent-free period received in 2004. The lease costs associated with the rent-free period will be recognized over the 10-year lease term.

Forward Contracts, Operating Reserves
The AESO uses ancillary services forward contracts solely to ensure an adequate supply of operating reserves is available as required by the Alberta Interconnected Electric System (AIES). The AESO does not enter into contracts on a speculative basis. Any gain or loss on these transactions is applied to the cost of the products purchased when the physical operating reserves are provided.

NOTE 3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION
The AESO’s transmission-related activities are regulated by the Alberta Energy and Utilities Board (EUB or regulator) and approved based upon the AESO’s annual General Tariff Applications. The following describes each of the circumstances in which rate regulation affects the accounting for a transaction or event.

Regulatory assets represent certain costs, incurred in the current period or in prior periods, that are expected to be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions of revenues associated with amounts that are expected to be refunded to customers as a result of the rate-setting process.

<table>
<thead>
<tr>
<th>Dec. 31, 2005</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulatory asset</td>
</tr>
<tr>
<td>Regulatory hearing costs</td>
</tr>
<tr>
<td>Regulatory liabilities</td>
</tr>
<tr>
<td>Transmission deferral</td>
</tr>
</tbody>
</table>

During 2004 and 2005, $72,000 was incurred in legal and consulting fees related to the AESO’s Energy Provision of Ancillary Services Article regulatory proceeding. The AESO intends to seek, and expects to receive, approval for recovery of these costs with the completion of the regulatory process. The regulator will issue a Utility Cost Order that approves allowable and recoverable hearing costs. If approved, the regulatory asset will become an other industry cost and will be recovered from customers in that year. If the cost claim is disallowed, the amount will be included in general and administrative costs in that year. In the absence of rate regulation, generally accepted accounting principles would require that such costs be included in operating results in the year in which they are incurred. The regulatory asset is included in accounts receivable on the balance sheet at Dec. 31, 2005.

At Dec. 31, 2005, the transmission deferral balance was $11.3 million based upon an accumulation of variances between transmission revenue collections and costs incurred from 2005 and prior years. On an annual basis, the AESO applies to the regulator for the approval and settlement of prior years’ deferral balances. The transmission deferral balance is a regulatory asset or liability, based upon the expectation that amounts accumulated from one year to the next will be approved for collection from, or refund to, customers in a subsequent year. In the absence of rate regulation, generally accepted accounting principles would require that such balances be included in a deferred charge/refund account in the year in which they are incurred given the AESO’s status as a not-for-profit organization. The regulatory liability is included in AESO deferral accounts payable on the balance sheet at Dec. 31, 2005.
All transmission-related financial activities of the AESO are subject to the regulator’s approval on an annual basis. With the formation of the AESO through the EUA, the AESO must be managed so that, on an annual basis, no profit or loss results from operations. The recovery of transmission costs through the transmission tariff is subject to regulatory approval and must be approved by the regulator. Management believes that the ultimate recovery is assured due to the not-for-profit status of the AESO.

**NOTE 4. AESO DEFERRAL ACCOUNTS RECEIVABLE (PAYABLE)**

<table>
<thead>
<tr>
<th></th>
<th>Current Portion</th>
<th></th>
<th>Long-Term Portion</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Transmission</td>
<td>Energy</td>
<td>Load</td>
<td>Total</td>
</tr>
<tr>
<td>Opening balance,</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current year</td>
<td>18,753</td>
<td>(987)</td>
<td>1,077</td>
<td>18,843</td>
</tr>
<tr>
<td>Closing balance,</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dec. 31, 2005</td>
<td>$ (11,322)</td>
<td>$ (5,821)</td>
<td>241</td>
<td>$ (16,902)</td>
</tr>
</tbody>
</table>

**NOTE 5. CAPITAL ASSETS**

<table>
<thead>
<tr>
<th></th>
<th>Cost</th>
<th>Accumulated Amortization</th>
<th>2005 Net Book Value</th>
<th>2004 Net Book Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy trading system</td>
<td>$ 11,410</td>
<td>$ 8,215</td>
<td>$ 3,195</td>
<td>$ 4,792</td>
</tr>
<tr>
<td>System coordination centre</td>
<td>11,406</td>
<td>9,406</td>
<td>2,000</td>
<td>3,756</td>
</tr>
<tr>
<td>Software development</td>
<td>18,192</td>
<td>3,590</td>
<td>14,602</td>
<td>4,380</td>
</tr>
<tr>
<td>Furniture, office equipment and computer hardware</td>
<td>5,800</td>
<td>2,744</td>
<td>3,056</td>
<td>2,154</td>
</tr>
<tr>
<td>Leasehold improvements</td>
<td>2,753</td>
<td>647</td>
<td>2,106</td>
<td>2,345</td>
</tr>
<tr>
<td>Work in progress</td>
<td>3,826</td>
<td>–</td>
<td>3,826</td>
<td>5,038</td>
</tr>
<tr>
<td></td>
<td>$ 53,387</td>
<td>$ 24,602</td>
<td>$ 28,785</td>
<td>$ 22,465</td>
</tr>
</tbody>
</table>

Work in progress in 2005 and 2004 relates to capital acquisitions associated with the relocation of the system coordination centre (occupancy date in 2006) and software development costs.

For the 12 months ended Dec. 31, 2005, interest costs of $30,000 were capitalized during the development phase of the system coordination centre relocation project (2004 – $0) and $1.4 million of payroll and payroll related costs associated with staff directly involved in software development have been capitalized (2004 – $0).
NOTE 6. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

<table>
<thead>
<tr>
<th></th>
<th>2005</th>
<th>2004</th>
</tr>
</thead>
<tbody>
<tr>
<td>Accounts payable, transmission settlement</td>
<td>$ 83,861</td>
<td>$ 66,329</td>
</tr>
<tr>
<td>Accounts payable, trade</td>
<td>25,880</td>
<td>14,335</td>
</tr>
<tr>
<td>Accrued liabilities</td>
<td>4,088</td>
<td>4,525</td>
</tr>
<tr>
<td></td>
<td><strong>$ 113,829</strong></td>
<td><strong>$ 85,189</strong></td>
</tr>
</tbody>
</table>

The accounts payable, trade balance includes flow-through customer contribution amounts of $20,101 in 2005 and $10,536 in 2004.

NOTE 7. CREDIT FACILITIES

The AESO has credit facilities of $110 million, comprised of a $50 million term revolving loan facility, a $40 million demand revolving loan facility and a $20 million demand non-revolving loan facility. The facilities provide that the borrowings may be made by way of operating advances, prime loans or bankers’ acceptances.

The $50 million term revolving loan facility is fully revolving for two year periods with a term to August 2007 and a provision for one extension. If the facility is not extended, the amount outstanding would be repayable in full in August 2007. Included in the $50 million term revolving loan facility is the option to request letters of credit.

In addition to the three loan facilities, a demand treasury risk management facility of $9 million in deemed risk content is available to provide for interest swaps for up to $35 million in notional debt. This facility was not used in 2005.

At Dec. 31, 2005, $6.1 million was drawn on and a $20 million letter of credit was issued on the term revolving loan facility, $24 million was drawn on the demand revolving loan facility, and there were no drawings on the demand non-revolving loan facility.

The amount of interest paid during the year was $1.0 million (2004 — $0.7 million).

NOTE 8. ANCILLARY SERVICES COSTS

In April 2004, a contract between the AESO and a supplier of transmission must-run services expired prior to successful negotiations of a new contract. As a result, payments made by the AESO for services provided have been made in accordance with the AESO’s interpretation of the Energy Provision of Ancillary Services Article of the transmission tariff and a letter of agreement. The AESO and the service provider do not agree on the compensation and continue to work toward a resolution.

At year end, this issue remains unresolved and any settlement amounts related to the difference between the payments that have been made to the supplier and the final decision for a settlement amount for the period from May 1, 2004 to Dec. 31, 2005 have not been incorporated into the transmission costs, as any difference is not determinable at this time. Amounts will be accounted for in the period they are determinable.
### NOTE 9. CONTINGENCIES AND COMMITMENTS

(i) The AESO leases office space, data processing equipment and land under various operating leases. The minimum lease payments associated with these leases are as follows:

<table>
<thead>
<tr>
<th>Year</th>
<th>Amount ($ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006</td>
<td>2.1</td>
</tr>
<tr>
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(ii) To fulfill the duties of the AESO in accordance with the EUA, the AESO manages the procurement of ancillary services through contracts with third-party suppliers. These ancillary services include operating reserves, transmission must-run, under-frequency mitigation and system restoration. The contracts are for generation capacity and load reduction capabilities ranging in contract duration from one day to 16 years. The amount to be paid under each contract is dependent upon fixed and variable terms. The variable terms are based upon commodity prices, dispatch volumes and frequency.

(iii) The EUA requires the AESO to provide funding for the MSA with the amount to be recovered through the energy market charge. In 2005, $2.7 million was paid to the MSA (2004 — $2.1 million).

### NOTE 10. PARTICIPANT SECURITY

All market participants and transmission customers who have financial obligations to the AESO must adhere to the AESO rules and transmission tariff terms and conditions regarding security requirements. Unsecured credit limits are provided for those organizations with acceptable investment-grade unsecured bond ratings, either directly or indirectly through a guarantee, and for organizations that are exempt as determined through government regulation. Security requirements for financial obligations in excess of unsecured credit limits are met with cash deposits and letters of credit.

### NOTE 11. FINANCIAL INSTRUMENTS

The AESO’s financial instruments consist of cash, accounts receivable, AESO deferral accounts receivable/payable, MSA deferral accounts receivable/payable, accounts payable and accrued liabilities, participants’ security deposits and bank debt. Due to their short-term nature, the fair market value of the financial instruments approximates the carrying value.
At the Alberta Electric System Operator (AESO), we're responsible for operating Canada's first competitive, real-time wholesale electricity market, which has nearly 200 participants and about $5 billion in annual energy transactions. As an independent system operator, the AESO leads the safe, reliable and economic planning and operation of Alberta's interconnected transmission power system.

We're focused on: planning and implementing transmission projects to strengthen the provincial grid; maintaining reliability in a more challenging real-time operating environment; efficiently connecting customers to Alberta's power system; and ensuring that Alberta's competitive electricity markets are fair, efficient and openly competitive.

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On the cover:
Kim Langille
Stakeholder Relations/Communications
Pung Toy
Transmission
Don Olson
System Operations
Marina Jagbandhansingh
Legal

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