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Electricity Transmission & Distribution Today

THE ELECTRICITY FORUM

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PLACING POWER IN THE NATIONAL INTEREST

By Don Horne, Editor

The U.S. Department of Energy said let there be light, announcing that the federal government could override state and local opposition to power line construction along the eastern seaboard.

The DOE stated that Virginia, Washington, D.C. and six other states are now part of a designated mid-Atlantic corridor, where electricity congestion is a significant problem.

The corridor is one of two National Interest Electric Transmission Corridors where the federal government can override local opposition to power line construction.

The other corridor consists of California and Arizona.

The Secretary of Energy Samuel W. Bodman has encouraged utilities to take prompt action, stating that "the goal is simple – to keep reliable supplies of electric energy flowing to all Americans."

For Dominion, the ruling could be insurance for a recent state application to build a high-voltage line from West Virginia to Loudoun County, Virginia. That application is currently under review by the Virginia State Corporation Commission. If the SCC rejects Dominion's application – and this appears unlikely – they could apply to FERC for approval to build the line.

Opponents of the corridors have testified at a spring DOE hearing that such corridors make the state process of applying for transmission lines irrelevant.

Robert Lazaro, a spokesman for the Piedmont Environmental Council (PEC), envisions utilities importing coal electricity through these corridors in places that won't receive the power. The PEC has gone on the record to reject the Dominion proposal, lobbying instead for increased efficiency over new power lines. Local politicians claim that the DOE has gone ahead in spite of public opposition to the corridors; the DOE states that it considered more than 2,000 comments from 60 public hearings held across the country.

The fears are that utilities will begin clear-cutting through neighbourhoods and historically significant lands, ignoring the new smart technologies for conservation that are becoming available.

In the case of Dominion, they point to an immediate need to meet demand that could plunge the region into blackouts unless a new transmission network is put in place now.

Maryland, having faced record electric rate increases following the move to deregulation, is pleased with the DOE order.

In fact, the current transmission shortfall for that state will result in even higher rates for Maryland residents, with a strong possibility of brownouts during peak usage times.

The pair of new power lines proposed in the corridor would increase transmission capability by 7,500 megawatts.

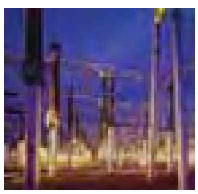
The renewed push to create more transmission corridors has generated the expected amount of opposition from environmental groups and residents wanting to look out their windows at green fields and thick forests instead of giant towers and transmission lines.

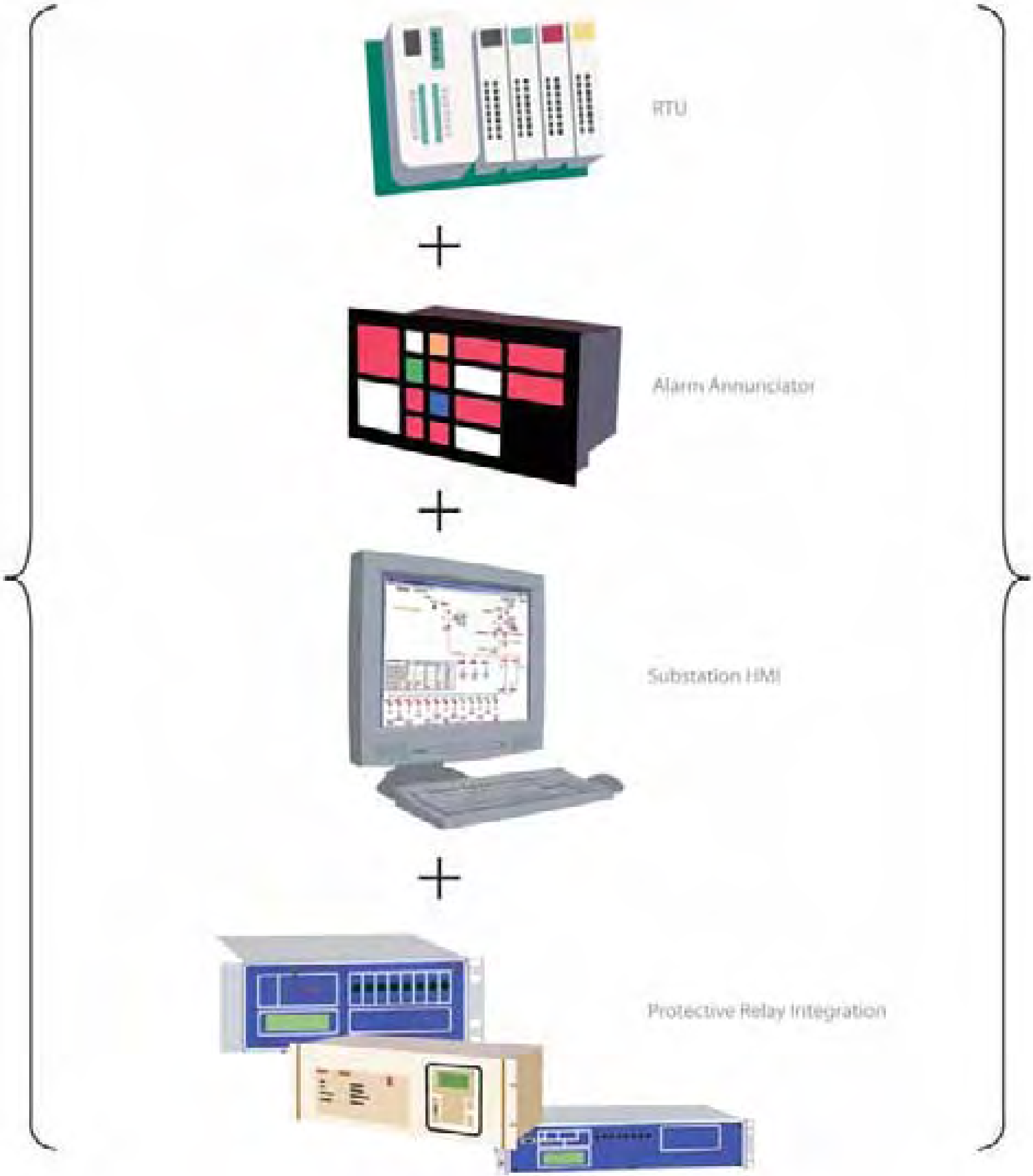
For local councils and state legislators, it is hard to ignore their constituents' pleas to keep their neighbourhoods intact. It is their votes that keep them in power.

Thankfully, the Department of Energy has removed this large stumbling block to the construction of new transmission corridors, shifting the responsibility from these elected officials to the federal body. Simply put, the state representatives can say, "Don't blame us, blame the DOE."

Admittedly, if given the choice, anyone would prefer to look out their window at nature's untouched beauty instead of a steel current of megavoltage flowing by their home. But the same could be said about the large interstate highways that are vital to the flow of commerce in the nation.

The miles of asphalt aren't pretty to look at, but they are necessary. And no less necessary to keeping the engines of commerce humming are these new transmission corridors.





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DETECTING SF6 INSULATING GAS LEAKS WITH AN IR IMAGING CAMERA

By Robert Madding and Robert Benson, FLIR Systems, Inc.

ABSTRACT

For years, electric utility transmission thermographers have wanted a camera that could spot leaking sulfur hexafluoride, SF6. As an insulating gas, SF6 is widely used by the electric power industry in high-voltage circuit breakers to prevent arcing. Early efforts met with limited success through the use of imagers that required active scanning with infrared lasers. The resulting systems were somewhat cumbersome and required specific conditions which limited their utility.

Now there is an IR camera that can spot SF6 in very small amounts and is a completely passive system, requiring no infrared laser but for the smallest leaks. This article gives a brief history of SF6 as an insulating gas, problems caused by leaking SF6, the theory behind the IR camera, and why it works as well as it does. Additionally, we present some sample findings from both the laboratory and actual operating circuit breakers in high voltage systems that use SF6.

Figure 1. GasFindIR LW viewing rupture disks on 500 KV live switchgear. Inset at right shows the GasFindIR mounted on tripod to exploit high sensitivity mode.

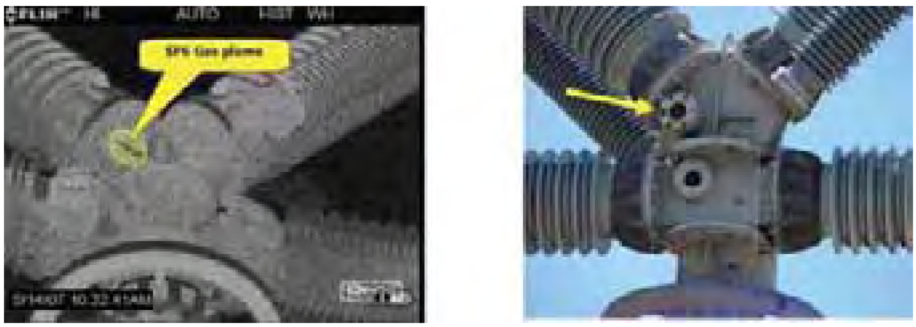

Figure 2. SF6 leak from rupture disk on 500 KV switchgear at 37 feet distance. Note the corrosion around the rupture disk bolts. In the video one can easily detect the leak coming from the bolt in the nine o'clock position.

IINTRODUCTION

In 1933, just after receiving his bachelor's degree, Ray Herb worked with Glen G. Havens at the University of Wisconsin, Madison on a vacuum-insulated electrostatic generator of the Van de Graaff design, but this device could not be pushed above 300 kV. There was no understanding of the discharges that limited the attainable voltage. Ray therefore decided to try to use high-pressure insulation. Two other graduate students, D. B. Parkinson and D. W. Kerst, joined Ray in this endeavor. Ray discovered accidentally that the dielectric strength of air could be greatly increased by the addition of carbon tetrachloride, an electronegative gas. According to Ray's story, he tried other chemicals. When he threw a rag soaked in acetone into the tank, the first spark started a fire. He was easily able to reach 1 MV in a pressure tank 1 m in diameter and 2 m long filled with air and carbon tetrachloride.

The basic features of Ray's design, which have been incorporated into all modern electrostatic accelerators, include aluminum hoops surrounding the acceleration tube, a voltage gradient controlled either by corona points or resistors, a rotating vane generating voltmeter, high pressure insulation (originally air and carbon tetrachloride, but later nitrogen and Freon or sulfur hexafluoride).

Having attended the University of Wisconsin graduate school in physics, Dr. Madding was fortunate to attend a colloquium that discussed Professor Herb's discovery of carbon tetrachloride (CCl4) as an insulating gas. The story he remembers from 30 years ago was that as a graduate student, Ray was working long hours and quite frustrated with not being able to achieve sufficient vacuum to keep the Van de Graaff generator from arcing. The accidental discovery mentioned above occurred when he was checking the system for vacuum leaks. In those days, one squirted acetone on suspected areas and watched the vacuum gauge. If the pressure dropped initially due to the acetone liquid temporarily plugging the leak, then rose rapidly as the high vapor pressure acetone liquid evaporated, you had your leak. Apparently,

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Sulfur Hexafluoride

Continued from Page 10

when Ray tried this, he accidentally picked up a squirt bottle of CCl_4. Not only did the pressure drop and then rise, indicating a leak, the system began to operate at higher voltages without arcing. Mystified by this event, Ray began experimenting with different gases as insulators. This eventually evolved into sulfur hexafluoride as the premier insulating gas, widely used today to insulate and prevent arcing in high-voltage switches and circuit breakers.

Figure 3. Using the GasFindIR to find and document leaks in an SF6 compressor cabinet.

In addition to electrical insulation, SF6 is used as a filler for bladders in athletic shoes, tennis balls, soundproof windows and tires. It is also used for the ultrasound measurements of tumors, as well as retinal eye repairs in the medical field. The US Navy also used SF6 as a propellant component in the Mark 50 Torpedo. It is also used as a cover gas in die casting to prevent oxidation of magnesium, and in the electronic industry for chip manufacturing. According to figures published in 2000, U.S. electric utilities used over 1.5 million pounds of SF6 as refill for leaks. At the current price of about $10/lb, this amounts to $15,000,000 annual cost to our electric utilities just to replace leaking SF6. Not to mention the reliability costs associated with potential downtime, outages and expensive repairs.

As a greenhouse gas, SF6 is 22,200 times more potent than CO2. According to the Intergovernmental Panel on Climate Change, SF6 is the most potent greenhouse gas it has ever tested. There is no doubt, from both a cost and environmental perspective, that finding and fixing SF6 leaks is in the best interests of our country and the planet.

Recognizing the cost of SF6, the environmental concerns and the reliability risk of SF6 leaks in high voltage equipment, electric power utilities and independent companies have spent years and invested thousands of dollars into developing technologies that can quickly, reliably and safely detect SF6 leaks. Power companies know when they have leaks as the pressure drops, and a one- or two-pound pressure drop on an 80-pound system can trigger an alarm, causing the system to default to an open condition. This creates reliability headaches, requiring power to be rerouted, and can even result in electric power outages.

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Sulfur Hexafluoride

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Probes, or sniffers, work with limited success as the probe must be close to the leak to detect it. With 500 KV switchgear, this can be problematic. Low voltage compressor cabinets are a prime target for sniffers, as they are safe and accessible. But a big problem is often the gas floods the cabinet, and when the operator opens it, the sniffer is overwhelmed with gas. It can take considerable time to clear the enclosure and sniff individual components to find the leak.

IR camera technology has been implemented with limited success using active scanning technology. Here, the IR camera system emits a laser beam at the same wavelength as the absorption band of SF6, 10.6 micrometers. The camera is designed to receive a reflected beam and display an IR image. When the laser beam intercepts an SF6 cloud, it is attenuated twice normally, once on the way out and once on the way back.

Figure 4. SF6 leak above pressure switch in compressor cabinet. This cabinet services a 230 KV capacitor bank.

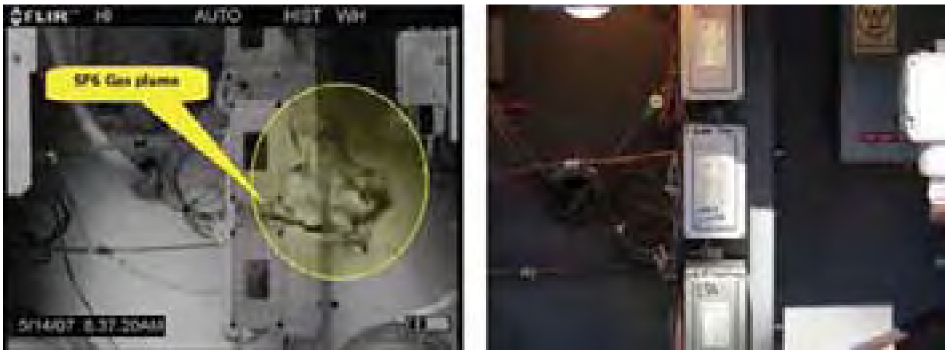


Figure 5. SF6 leaking from a cracked bellows on a governor switch.

The problem with such a system is there must be something to reflect the beam. Pointed at the sky, nothing returns, and you cannot detect an SF6 cloud. The system was also very large, not very simple to operate, and prone to breakage.

Recently a new IR camera based on a robust design for military applications has proven quite adept at finding SF6 leaks. It is small, quite portable and extremely sensitive to SF6. The camera is completely passive and can find leaks as close as a few feet and as far away as tens of yards. A competent operator in a substation or high-voltage yard won't miss much, if anything with this camera.

HIGH-VOLTAGE SUBSTATION EXAMPLE APPLICATIONS

Figure 1 shows a picture of the SF6 camera in operation at a 500 KV substation. Manufactured by FLIR Systems, Inc. the camera's official name is the GasFindIR LW, as it finds gases with absorption bands in the long-wave portion of the IR spectrum. (There is a sister camera, the GasFindIR which works in the mid-wave band of the IR spectrum and is useful for detecting volatile organic compounds (VOC) gases.)

Based on laser rangefinder measurement, the rupture disks are 37 feet from the IR camera. Four of these 5-inch diameter disks can be seen in Figure 1, two on each tower. Figure 2 shows a close-up image of one of these rupture disks with associated GasFindIR infrared image. In a still picture, the leak is very difficult to see, so we highlighted the leaks in the black and white images for this article. This helps compensate for the frozen image perspective necessary in the written document. With the live IR camera or its recorded video, the leaking gas plume, though small, is easy to spot as its motion gives it away.

Documentation with a digital visual camera is an important complement to the GasFindIR video. There are numerous good digital cameras available. We used a Nikon S10 Coolpix digital camera with 6 megapixel resolution, 10X zoom and vibration reduction. It is pocket size for a large pocket. The hand-held photos came out surprisingly well. We used an Archos digital video recorder to capture the standard video output of the GasFindIR.

There was a light breeze when we found this leak blowing about 5 to 10 mph. The wind was slightly up-wind and cross-wind from the leak, somewhat in the direction of the arrow in the visual image in Figure 2. The breeze did not hamper our seeing the leak. It did cause the SF6 to disperse perhaps more quickly, making finding an individual still frame representative of the leak difficult. There is more gas than meets the eye in the image in Figure 2.

Finding leaks in areas such as this would be very difficult and time consuming with hand-held "sniffer" devices, as access is difficult and the power would need to be removed from the circuit for safety. With the GasFindIR LW, we were able to safely survey and document the entire substation in less than two hours with everything remaining fully operational.

Areas of a substation that have spare SF6 tanks strapped to the structure are places of "low hanging fruit" for SF6 leak detection. The electric power company usually knows it has leaks, as the pressure is closely monitored. For reliability, they maintain a state of readiness to replace leaking gas. In addition to rupture disks, compressor cabinets are a good place to look for leaks.

Figure 4 shows a leak near a pressure switch. Though we were not authorized to perform repair work, we believe a simple tightening of a fitting could repair this leak. The gas is coming from one of the connections on the tee fitting just above the pressure switch. The opening to this cabinet was downwind from a 15 to 20 mph breeze. Even on the lee side, the wind caused a lot of swirling inside the cabinet. However, the leak was still quite obvious on the video. We also noticed a periodicity to this leak, not exactly puffing, but sometimes it appeared to leak more strongly than at other times. This is the area the GasFindIR was viewing in Figure 3.

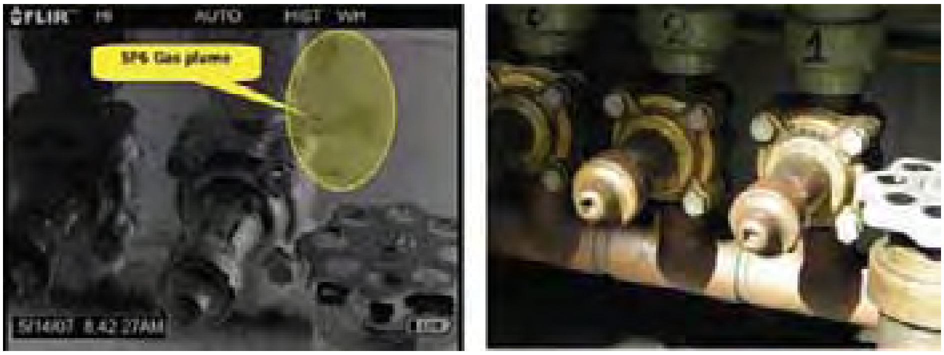


Figure 6. Diaphragm leak.

Other compressor cabinet opportunities are shown in Figures 5 and 6. This cabinet had two leaks, the larger being a cracked bellows, Figure 5. The cracked bellows leak was large enough to be visible in the normal mode. The other leaks were easily detected in the high sensitivity mode, but not initially so in the normal mode. High Sensitivity Mode, (HSM), is a newly developed feature specifically designed to find small gas leaks in the GasFindIR LW. It uses an adaptive motion filter that brings the leaking gas into plain sight and makes leak recognition far easier. After we found them, we tried the normal mode and could sometimes see them, though we already knew they were there.

When we approached the leaking switch to take a digital photo, we noticed the utility personnel had already found the leak and labeled it. Our host was interested to see how long it took us to find it with the GasFindIR.

It took us less than two minutes once the compressor cabinet doors were open. The smaller diaphragm leak in Figure 6 took only moments longer to locate. Of the leaks reported in this article, these were the only two the electric utility had located.

Because one is looking for motion when detecting these leaks, having the IR camera stable is imperative. We used a professional photographer's tripod. It had a regular camera head on it. For future work, a video head would work better.

The primary author has years of experience in using IR thermography in substations to look for thermal anomalies, usually hot spots in electrical connections. The approach with the GasFindIR is different. You cannot go fast. You need to set up the camera on the tripod, focus on an area, get a good image and stare at it for a while. Heat is not the key here. Thermal contrast of moving SF6 gas against a stationary background is what you're looking for.

SUMMARY

The new GasFindIR camera worked extremely well for finding SF6 leaks in both 500 KV and 230 KV substations. The technology has finally evolved to the point where a battery operated, rugged, small and lightweight camera can be easily taken into a substation and can rapidly find the leaks.

We found some operational tricks and environmental conditions that help optimize SF6 gas leak detection in substations:

• Gas motion is the key. Keep the IR camera on a good, stable tripod and watch for movement. Use the HSM feature - it will highlight the gas against the background.

• Thermal contrast between the SF6 plume and its background is important. We tried some pre-dawn work and our success in finding leaks we had found the day before was limited. Solar loading is a good thing for SF6 detection. Warm cabinets, insulators and so on make a good background to the cooler gas. Against a clear, cold sky, SF6 will appear warmer.

• Wind can be problematic. We didn't have much trouble in a 5 to 10 mph breeze, but a 15 to 20 mph wind presented some difficulties. A little swirling is OK. But when the wind is blowing strong enough to really "scrub" the SF6 off its leaking point, you will probably miss some.

AREVA LOOKS AT DEVELOPING WORLD ENERGY WITH AN EYE TO THE ENVIRONMENT

The challenge of providing the world with energy without damaging the environment continues to be a key part of the environmental issues that the planet faces in the 21st Century. Not only is the general public realizing this issue is far from over, but businesses across the world also understand the importance of their responsibilities towards environmental friendliness, social understanding and economic development. The electrical energy transmission and distribution industry is one industry that is devoting effort to ensure that products and processes have as little impact on the ecology as possible.

Dr. Jean Luc Bessède, Director of Innovation and Eco-Design at AREVA T&D, discusses the continued commitment the company has made to its eco-design programme over the last ten years. He explains how all of the business units strive towards designing and delivering products and services which are as economical as possible with the Earth's resources. This is demonstrated through AREVA T&D's "cradle-to-cradle" design process that is, designing a product for recycling at the end of its useful life rather than disposing of it into dips or incinerating it.

Transmission and distribution is no different from any other industry in the sense that it has a commitment to help protect the earth's environment. Eco-design is a concept that focuses on integrating the environmental dimension into the design phase of a new product, just like other considerations such as standards, customer specifications, technical feasibility, product cost and so on that has been undertaken in a large way by AREVA T&D. With the pressure on both companies and individuals to reduce the use of fossil fuels and cut down carbon emissions into the atmosphere, this is the time action must be taken to ensure a better world for the future.

AREVA T&D is making great strides in opening up the Asian-Pacific market.

Over the past ten years, products and services within AREVA T&D have been continuously improved to maximize the benefits for the environment and also to our customers. AREVA T&D's corporate responsibility has three pillars; economic development, social understanding and environmental friendliness, and our eco-design programme is an outcrop of the latter. The earth only has a limited supply of resources and if companies as well as individuals do not take the time to ensure measures are in place in order to improve the state of the environment, the world will eventually run out of fossil fuels and other resources causing a major world crisis. By taking ecological considerations throughout the creation of our products, we feel confident we are making a difference to the future of the earth.

A key component of the eco-design programme is the "cradle-to-cradle" design process. This has been adapted from "cradle-to-grave" to mean that instead of being discarded after use, products are designed to be recycled at the end of their useful life. A significant example of this is the way in which the materials from our 72 kV and 145 kV gas-insulated substations (GIS) are dealt with. "We put a great deal of effort into increasing the amount of materials we recycle, as this ultimately means less waste at the end of life, and we are finding ways to reuse the SF6 gas used in GIS to avoid releasing it into the atmosphere. This has meant that we are able to substantially reduce our emission which, in turn, decreases the impact we have on global warming", said the Manager of Technical Consulting in the R&D Department, Mr Endre Mikes.

To further AREVA T&D's commitment to sustainable development, we have been working to extend the use of vegetable oils in the place of mineral oils. There has been increasing demand to create environmentally friendly and safer transformers and reactors, which has resulted in the organization carrying out extensive research and development throughout the eco-design process. Two recent projects, one in the UK and one in Brazil, have demonstrated such an approach where vegetable oil was used instead of mineral oil as the insulating fluid for the transformers. The vegetable oil that was chosen was soybean based Envirotemp®FR3™ which is biodegradable and offers increased safety and insulation life, but most importantly, it originates from a renewable source. This means, not only is the solution offering benefits to the environment, but it is providing increased fire safety and longevity to the transformers. Through this initiative of increased use of vegetable oil, AREVA T&D is able to offer customers innovative solutions for a sustainable future.

Within Transmission and Distribution, Distributed Energy Resources (DERs) are an integral component towards helping to answer the climate change issue and augmenting fuel diversity. These allow local sources of energy to be exploited but they are beginning to cause operational problems. AREVA T&D has become a key partner in the FENIX (Flexible Electricity Networks to integrate the eXpected energy evolution) European Consortium, supported by the European Commission, which aims to tackle this problem and create DER-based systems to become the solution for the future of EU electricity supply. FENIX aims to design and demonstrate a technical architecture and commercial framework that would make this concept become a reality. As the IT provider, AREVA T&D will demonstrate the feasibility of these novel concepts to the energy community. With the specifications already written, the first field test is scheduled to take place in Woking, UK during 2008.

Throughout all the work AREVA T&D carries out to ensure the success of the eco-design programme, it is necessary to make sure that each individual business unit is meeting acceptable standards in the process of achieving a sustainable future. The success of the programme is based upon continuous improvement and activity to ensure high quality products and services are on offer. The four business units, Products, Services, Systems and Automation are making self-assessments on a regular basis to ensure they are meeting the specifications for the eco-design programme. There are eleven points on which they are based; each rated from zero to four. A few years ago, the average was 1.5, but it is now at 2.3 and the organization aims to reach 2.8 by 2009 on the four point scale. By setting standards we want to live up to, it motivates us to continue developing our products to make them as environmentally friendly as possible.

One reason it has been possible to develop such a successful eco-design programme is due to that fact that there has been immense investment both

financially and in terms of training for our staff. To be able to constantly evolve our products, it has been necessary to invest a high amount of capital to make the programme feasible, but in terms of the benefits created, it has been worth it. Additionally, we feel that training is the first step to making our employees more environmentally aware which will allow them to have a greater understanding about what they are working towards. The financial investment and the ongoing training will also ensure that the benefits our products and services are able to offer are maximized.

In the 21st Century, eco-design products should be part of the norm. Although it requires a high level of investment, it is an investment for the future of the earth which makes it all the more important. GIS, the use of vegetable oils, and our involvement in FENIX are just some of the ways we are altering our business practices to promote a sustainable future. There is a need for everyone to make the best of earth's resources before it is too late. AREVA T&D's commitment to the eco-design programme will continue and evolve as we look towards the future to further our corporate responsibility and ensure that we are an eco-friendly organization.

ELECTRICITY STRUCTURE AND THE IMPACT ON PRICING, TRADE AND THE ENVIRONMENT

By Pierre-Olivier Pineau, Associate Professor, HEC Montréal

A lot has been written on electricity market structure. Much less is discussed on integrating different electricity markets, on the kind of benefits it could bring, and – even more critically – on estimating these benefits. This article shows that important differences in Canadian electricity markets create distortions that are economically and environmentally harmful. Important indirect subsidies are provided to electricity consumers in many provinces, which leads to inefficient consumption levels – and to missed environmental gains.

An estimated total yearly subsidy of $10 billion is indeed offered to consumers in only four provinces (British Columbia, Saskatchewan, Manitoba and Québec), preventing a reduction of up to 57,000 kilotons of greenhouse gases (GHG) emissions to happen. Such a reduction represents almost a third of the Kyoto reduction effort required from Canada, based on the 2005 emission level.

1. THE CANADIAN ELECTRICITY SECTOR STRUCTURE

1.1 Ownership, price and capacities

The Canadian electricity sector structure is characterized by two very strong features: public ownership and decentralization at the provincial level. Decentralization has produced ten different electricity sectors, with independent planning, pricing policies and environmental strategies. Public ownership, dominant in seven out of ten provinces, creates incentives to keep a pricing policy based on costs, especially when costs are low, as is the case in provinces with high hydropower capacity. This is so because governments, although reaping public companies' profits, are under pressure from the electorate and industrial interest groups to sell electricity according to average cost principles, which maintains low and predictable prices.

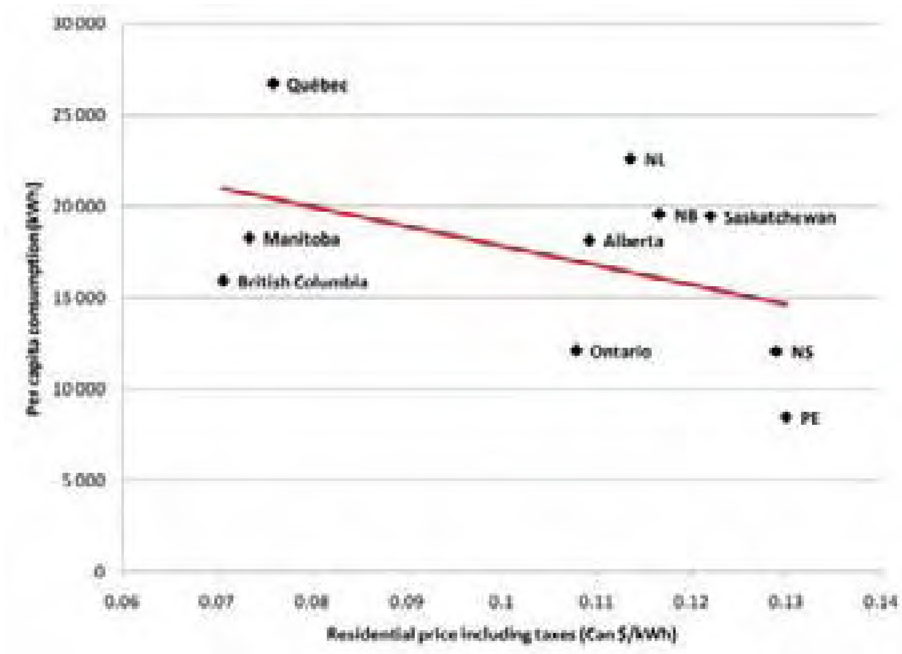


Figure 1. Per capita electricity consumption and price, 2006 (Statistics Canada, 2007 and Hydro Québec, 2006)

Type of Electric Generating Unit (EGU)	AB	BC	MB	ON	QC	SK	Total
Hydro	815	12,369	5,427	7,627	37,238	849	64,324
Nuclear				12,278	680		12,958
Unscrubbed Coal-Subbituminous	5,225		100				5,325
Oil/Gas Steam	1,048	1,017	132	2,146	600	217	5,160
Unscrubbed Coal-Bituminous	145			5,013			5,158
Cogeneration - Combined Cycle	1,799	240		1,585	550	475	4,649
Combustion Turbine	421	205	269	286	1,004	162	2,348
Unscrubbed Coal-Lignite				525		1,716	2,241
Biomass - Wood and Wood Waste	278	568	23	271	261	63	1,464
Cogeneration - Combustion Turbine	911	110		308			1,329
Combined Cycle	460			580		150	1,190
Unscrubbed Coal (Selective Catalytic Reduction Bituminous)				980			980
Coal (Selective Catalytic Reduction and SO2 Scrubber)				980			980
Cogeneration - Oil/Gas	155	63		224		21	463
Wind	302			17	102	33	454
Scrubbed Coal	450						450
Combined Cycle	4	29		168			201
Pumped Storage				174			174
Other	27			104	29		160
Total	12,040	14,601	5,951	33,265	40,464	3,687	110,008

Table 1. Nameplate capacity of existing and planned electric generating unit in six provinces, MW, 2005

Low-cost electricity from hydropower in British Columbia (B.C.), Manitoba and Québec results in higher per capita consumption than in other, higher cost, provinces. This can clearly be seen in Figure 1, where per capita consumption (total provincial electricity demand divided by total population) decreases as price increases (residential price is used as a proxy for provincial price level). Of course, many other factors contribute to electricity consumption, such as economic activity (GDP), industrial structure, temporal behaviour patterns and weather. This explains why in Figure 1, despite a clear trend, there are significant variations. Table 1 shows the installed capacity by type of generating units for six of the ten Canadian provinces.

But strong public ownership does not necessarily entail price regulation, as Ontario, and to a lesser extent Alberta, prove. Both provinces have important provincial or municipal government owning electricity companies and an hourly spot market, fixing the electricity market price. All other provinces use a pricing policy based on average cost, including a return on investment, with very little concern for marginal costs (and consequently, for economic efficiency). New Brunswick has a bi-lateral contract system, where prices are not regulated and where there is no open hourly spot market.

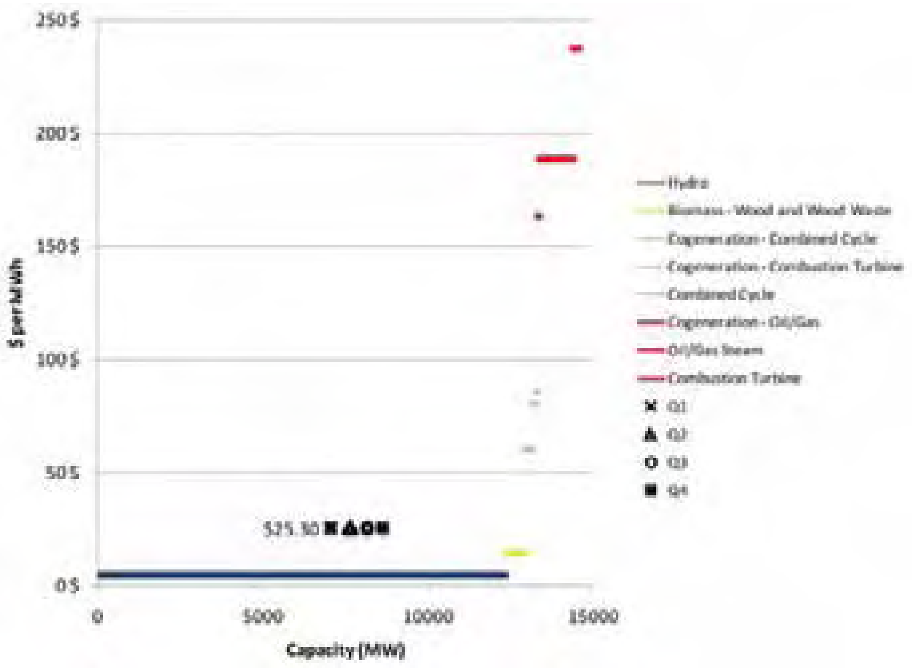


Figure 2. B.C. electric generating units by marginal generation cost and demand data, $/MWh, 2006

1.2 Market outcomes

The different provincial electricity market structures allow very different market outcomes to be observed across

Canada, as already seen in Figure 1. This is a unique situation in the energy sector, where despite some regional differences, gasoline and natural gas prices follow similar trends. In electricity, electric generating units (EGUs) are specific to the province and are mostly dedicated to satisfy provincial electricity demands, because of regulation or lack of trading possibilities.

These very different market outcomes are illustrated in more details through Figures 2 and 3, displaying the EGUs ordered by increasing marginal production cost in B.C. and Alberta. The actual market outcomes are displayed for the four "load quartiles". These load quartiles are four demand periods of equal length (one fourth of the year or 2,190 hours) with increasing demand. For each of these quartiles, the average load and average energy price can be obtained. In B.C., the energy price is regulated and is $25.30/MWh. It stays constant for consumers in all quartiles. That is, as the average load quartile increases

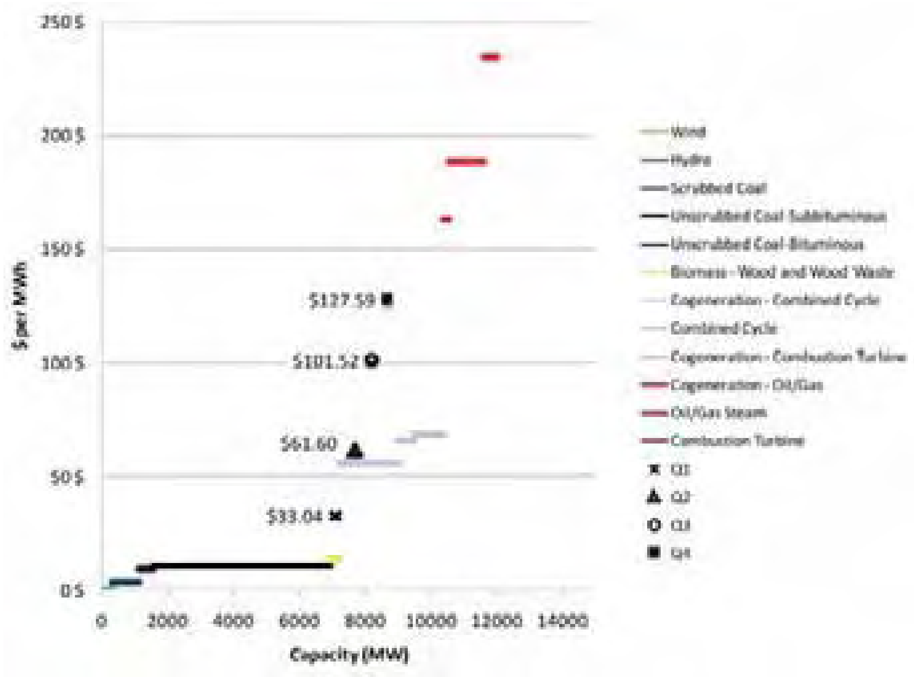


Figure 3. Alberta electric generating units by marginal generation cost and demand data, $/MWh, 2006

from 7,073 MW (Q1), to 7,661 (Q2), to 8,159 (Q3) and to finally 8,645 MW (Q4), the energy price remains the same for consumers (see also Table 2 for these average load quartiles). Hydro EGUs can by used to meet demand most of the time, avoiding the use of more expensive EGUs.

In Alberta, the market price for energy increases with demand levels: when demand is low (Q1: 7,104 MW on average), the average market price for this quartile is $33.04/MWh (2006 market price, see also Table 2). As demand rises to higher levels, price increases to reflect the higher marginal value of the product. In Q2 (average load of 7,695 MW), the average market price is $61.60/MWh. In Q3 (8,195 MW), the market price is $101.52/MWh, and during the peak quartile (Q4), an average load of 8,683 MW is sold at $127.59 per MW, on average, at each hour.

This situation perfectly illustrates the following economic paradox: while some consumers value a single megawatt-hour at $127, on average, during 2,190 hours in Alberta, BC Hydro is selling energy to its consumers at $25. Of course, at $127/MWh, some expensive EGUs are economic to operate in Alberta, such as natural gas power plants (cogeneration-combined cycle, combined cycle, cogeneration-combustion turbine) and therefore, they produce. Meanwhile, in B.C., consumers facing the relatively low energy price of $25/MWh use the plentiful hydropower resources they have, indirectly ignoring $102 they could make by selling in Alberta instead of using the electricity in B.C. This is a very high opportunity cost.

This captures the core of the argument:

1. Electricity prices do not reflect the value of the resource across Canada.

2. This situation accounts to a subsidy indirectly given to some consumers (those in low-cost, regulated-price provinces).

3. These low prices result in inefficient consumption levels, preventing "clean" hydropower to be exported to market-based provinces, becoming a substitute to diesel, natural gas and/or coal-fuelled EGUs.

4. With such exports (and adequate transmission capacity), important reductions of GHG could be obtained.

The next section presents an estimate of the indirect subsidy mentioned in point 2 of the argument. Section 3 analyzes possible consumption reduction scenarios if market prices were used and estimates CO2-equivalent emission reductions that could be obtained if the "saved" energy was entirely exported. Finally, section 4 presents the transmission issues involved in exporting this energy.

2. ELECTRICITY SUBSIDIES IN CANADA

A subsidy in the energy sector is defined as "any government action that lowers the cost of energy production, raises the price received by energy producers or lowers the price paid by energy consumers". Similar definitions can be found in documents of various international institutions, such as the OECD's International Energy Agency (IEA, 2000) or the U.S. Energy Information Administration (EIA, 2000). In many Canadian provinces, price regulation of electricity "lowers the price paid by energy consumers" because the price is based on the average cost rather than on the marginal value of the product. As Figures 2 and 3 show, not only the marginal production cost of electricity rises with quantity, but consumers value electricity at higher levels during peak periods – they are ready to pay a higher price for it. Consequently, consumers in B.C., Saskatchewan, Manitoba and Québec benefit from an indirect subsidy given by their provincial government through regulated, cost-based electricity prices.

2.1 Methodological discussion

To estimate this subsidy, a reference price has to be found. This reference price can be a forecasted market price (with a market model), the price under an alternative technology, the export price or the long-run marginal cost. The subsidy is estimated by the difference between the market price and the regulated price paid by consumers. This approach to estimate energy subsidies is also known as the "price-gap" approach.

Here, the reference prices chosen are the average quartile market prices in Alberta, for B.C. and Saskatchewan, and the average quartile market prices in Ontario, for Manitoba and Québec. These reference prices are not perfect, but no reference price can be ideal. In particular, these reference prices can over- or under-estimate the actual market price that would be observed in the different provinces if market prices were introduced. But as introducing market prices comes with high uncertainty on price levels, there is an inherent uncertainty in the market price level that cannot be avoided. The choice of the Alberta and Ontario market prices is a compromise between using real market prices, alternative technologies and export prices.

In order to find the reference market price for each quartile of the year, the following procedure is followed. The year 2006 is divided in four "load quartiles". The lower quartile groups the 25% lowest loads of the 8,760 hours of the year (these loads are the smallest required capacities to meet demand). The second quartile groups hours that have a load above the 25% lowest but below the median. The third quartile groups those above the median but below the 25% highest. Finally, the fourth quartile groups hours with the top 25% loads. Each quartile contains 2,190 hours (one fourth of the 8,760 hours).

Hourly load and price data are only publicly available for Alberta and Ontario. From these data, it is easy to compute the average load and price for each quartile. Table 2 provides this information for Alberta and Table 3 for Ontario. Based on the proportion of the peak load each of these "average quartile loads" represents, average quartile loads are estimated for B.C. and Saskatchewan (based on the Alberta values) and for Manitoba and Québec (based on Ontario values). The real 2006 peak load data are used when available for each province (when not available, 2004 peak load is used).

	BC		Alberta		Saskatchewan	
Peak demand 2004, MW	9,619		8,967		2,800	
Peak demand 2006, MW	n.a.		9,661		n.a.	
	Average MW	Energy price $/MWh	Average MW	Energy price $/MWh	Average MW	Energy price $/MWh
Q1	7,073.86	25.30	7,104.75	33.04	2,059.135	25.12
Q2	7,661.96	25.30	7,695.41	61.60	2,230.324	25.12
Q3	8,159.76	25.30	8,195.39	101.52	2,375.229	25.12
Q4	8,645.34	25.30	8,683.09	127.59	2,516.577	25.12
Average energy cost		25.30		80.90		25.12

Table 2. Peak demand, average quartile demand and energy prices in BC, Alberta and Saskatchewan in 2006

	Manitoba		Ontario		Québec	
Peak demand 2004, MW	3,916		25,000		36,279	
Peak demand 2006, MW	4,173		27,375		n.a.	
	Average MW	Energy price $/MWh	Average MW	Energy price $/MWh	Average MW	Energy price $/MWh
Q1	2,206.26	16.44	15,422.99	27.09	20,439.48	27.90
Q2	2,534.05	16.44	17,714.40	40.52	23,476.19	27.90
Q3	2,772.49	16.44	19,381.21	50.92	25,685.15	27.90
Q4	3,097.90	16.44	21,656.05	66.21	28,699.90	27.90
Average energy cost		16.44		46.38		27.90

Table 3. Peak demand, average quartile demand and energy prices in Manitoba, on and Québec in 2006

The B.C. price is the "Forecast Heritage Reference Price". The Alberta price is the average hourly pool price (average System Marginal Price) for the four quartiles. The Saskatchewan energy "price" is the average fuel and purchased power costs for 2006.

The Manitoba "price" is the average cost for water rentals and fuel and power purchases. The Ontario price is the average Hourly Ontario Energy Price (HOEP) for each quartile. The Québec price is the "Heritage Pool" price.

As Tables 2 and 3 show, energy prices are much higher in market-based provinces than in average cost provinces. The Alberta price is also much higher than the Ontario price. A few explanations can be given to explain the Alberta-Ontario differences. First, Ontario has access to more low cost EGUs than Alberta. As shown in Table 1, Ontario has important hydro and nuclear capacities, which allow the province to avoid using expensive EGUs as often as in Alberta (most of these EGUs are fuelled by natural gas). Second, Ontario is currently more interconnected with its neighbours than Alberta. This allows imports to limit the market price increase when demand is high, compared to a situation where there would be no or little import opportunities, as in Alberta. Finally, Ontario consumers may be more price responsive than Alberta consumers – although no specific empirical justification for such an hypothesis is known to the author.

	Province used for the market reference price (average quartile price)	Approximate number of TWh sold during the four quartiles	Estimated subsidy, million of dollars
British Columbia	Alberta	69.07	4,027.49
Saskatchewan		20.11	1,175.98
Manitoba	Ontario	23.24	735.83
Québec		215.28	4,350.68
	Total	327.70	10,289.99

Table 4. Estimated subsidy in the four regulated provinces

2.2 Results

Using the real average quartile prices of Alberta and Ontario, the difference between these prices and the actual price paid in the four other provinces can be found (B.C., Saskatchewan, Manitoba and Québec). Multiplying the consumption in these provinces, for each quartile, by the corresponding price difference, an estimation of the subsidy can be provided for each province. Table 4 shows these estimates.

Table 4's subsidy estimates simply reflect the amount "saved" by consumers, had they purchased the same amount of electricity at the market price of Alberta or Ontario. The total amount, about 10 billion dollars, indicates that this indirect subsidy (for 2006 only) is large. Two comparison points can be provided: the income of BC Hydro for 2006-07 was almost $4.2 billion, and the income of Hydro Québec a little more than $11 billion. These companies would increase their income by 100% and almost 50% under this scenario, with a very large share of the additional revenue simply being profit In economic terms, these companies would keep the rent that is now distributed to their consumers.

If these estimated subsidies are high, they simply reflect the high gap between the marginal value of electricity, as valued in markets, and the production costs on which the price is based in these provinces. To reach economic efficiency, however, there should be no such gap. In a world where consumers in regulated price provinces would face market prices, they would however not buy the same amount of electricity: they would reduce their consumption. The next section explores these consumption reductions.

3. IMPACT OF MARKET PRICE: POWER SAVING AND GHG REDUCTIONS

If electric energy in regulated provinces was sold at market price, the final price of electricity for consumers would increase by a significant amount, as illustrated in Table 5. This increase would, in turn, lead to a consumption decrease, depending on the price elasticity of consumers. Espey and Espey (2004) have surveyed a large number of studies estimating the price elasticity of residential electricity consumers, and have found that the average price elasticity is -0.35 in the short-run and -0.85 in the long run.

Table 5 presents the residential price faced by consumers in 2006 (shown in Figure 1) and the average additional energy cost that would be added to these prices if energy was sold at the reference market prices (Alberta and Ontario). From these two price items, the price increase can be computed, and given some price elasticity levels, consumption decreases can be estimated.

As we can observe in Table 5, the price increase could be very high in percentage points, or could be relatively small: 24% in the case of Québec. Consumption reductions for electricity, a relatively inelastic product, would be of a much smaller scope, in percentage points. If market prices in Alberta were lower, then the price increase in B.C. and Saskatchewan would not be as important. One can also notice that the price increase in Manitoba and Québec would not even bring the residential electricity price to the Ontario level… which is higher due the different additional charges Ontarian electricity consumers have to pay (i.e. regulatory and debt retirement charges, among other). Price increases, in percentage points, would of course be smaller for higher voltage consumers (mostly industrial consumers), because they face lower distribution costs. Their consumption reduction would therefore be more modest than the ones listed in Table 5. This is why more limited consumption reduction scenarios are explored from here: one with a 10% consumption reduction, and one with 20%. Table 6 shows these results.

These electricity consumption reductions would be available in the export markets. By adding energy to the available supply in export markets, they would "push to the right" more expensive EGUs in supply curves such as the ones displayed in the Figures 2 and 3. This means that these more expensive EGUs would be used less often. As these units use diesel, natural gas and coal as fuel, the associated CO2-equivalent emissions would be avoided. Table 7 estimates how much of these emissions would be avoided if electricity consumption reductions were entirely exported. Only B.C., Manitoba and Québec electricity is included here, as they produce almost only hydropower. Saskatchewan does not produce hydropower, so it could not export "clean" energy. Table 7 also presents two possibilities: hydropower replacing natural gas-fuelled EGUs or coal-fuelled EGUs (diesel units have been ignored because they are only exceptionally used in Canada).

Considering that 747,000 kt of GHG were emitted in 2005 (the latest year for which an inventory has been made) with 129,000 from electricity and heat generation, CO2-equivalent reductions presented in Table 7 are non-negligible. Indeed, from 10% to almost 50% of electricity-related GHG could be avoided by simply introducing market based prices in four regulated provinces, and exporting the "saved" electricity to Alberta and Ontario.

With a Kyoto target of 563,000 kt, these GHG reductions represent between 7.05% and 31.46% of the reduction effort to achieve Kyoto. Indeed, a reduction of 184,000 kt is needed to reach the Kyoto target from the 2005 level, and a very conservative 12,980 (7.05% of the reduction) could be achieved simply by increasing economic efficiency through market prices. No carbon tax or tradable permit system is involved in these scenarios. Of course, such carbon tax or cap-

	Residential price (Including transmission, distribution and other costs and taxes) 2006, $/kWh (Hydro Québec, 2006)	Additional energy cost $/kWh	Price Increase	Consumption decrease According to elasticity	
				Short run -0.35	Long run -0.85
BC	0.0707	0.0556	79%	-27%	-67%
Alberta	0.1093				
Saskatchewan	0.1220	0.0558	46%	-16%	-39%
Manitoba	0.0734	0.0299	41%	-14%	-35%
Ontario	0.1079				
Québec	0.0759	0.0185	24%	-8.5%	-21%

Table 5. Price increase and consumption decrease, according to possible elasticity values

Consumption reduction	BC	Saskatchewan	Manitoba	Québec
10%	6.91	2.01	2.32	21.52
20%	13.81	4.02	4.65	43.05

Table 6. Estimated power consumption reduction in regulated provinces (TWh)

and-trade systems would further increase the value of trading electricity across Canada.

	kt of CO_2-equivalent emissions per TWh (Hydro Québec, 2003)	Electricity consumption reduction scenario 10%	20%
If hydro replaces natural gas	422	12,980	25,960
If hydro replaces coal	941	28,944	57,888

Table 7. Kilotons of CO2-equivalent reduction from BC, Manitoba and Québec exports

4. EXPORT AND TRANSMISSION ISSUES

The export of electricity is only possible if enough interconnections exist between provinces. Table 8 shows that not only these interconnections exist, but they are already used to export within Canada between 12% and 69% of the total electricity exports. However, paradoxically, current interconnections to Alberta and Ontario only represent between 10% and 20% of the export capacity of the four provinces discussed here. This reflects the fact that very limited investment has been done to increase provincial trade. To some extent, these limited capacities "protect" high market prices in market-based provinces.

	Exports to all Canadian provinces TWh (% of total)	Total exports TWh	Interconnection capacity MW (% of total)		Total export capacity, MW
BC	1.05 (17%)	6.15	to Alberta	800 (20%)	3,950
Saskatchewan	1.34 (69%)	1.94		75 (10%)	725
Manitoba	2.19 (12%)	14.47	to Ontario	275 (10%)	2,800
Québec	3.56 (23%)	15.28		1,372 (12%)	11,352

Table 8. Exports from BC, Saskatchewan, Manitoba and Québec, 2006

If only new transmission lines were built to export the electricity available through consumption reductions (10% reduction scenario), a total investment of less than $8.5 billion would be needed, as shown in Table 9 for the four provinces.

	Distance between "regional centroids", km (EC, 2005)	Additional possible exports under the 10% consumption reduction scenario TWh (from Table 6)	Required transmission capacity if lines are used at 50%, MW	Estimated construction cost at $1,113/MW/km (EC, 2005)
British Columbia (to AB)	620	6.91	1,577	$1,104,878,578
Saskatchewan (to AB)	543	2.01	459	$281,676,619
Manitoba (to ON)	1,155	2.32	531	$692,427,775
Québec (to ON)	1,155	21.52	4,915	$6,414,858,850
		Total	7,482	$8,493,841,823

Table 9. Estimated investment in transmission capacity to export all energy saved to Alberta and Ontario

Results in Table 9 are based on standard assumptions made in transmission. It is interesting to notice that the total long-term investment is less than the total single year subsidy given to consumers in the four provinces.

5. INSTITUTIONAL OBSTACLES

Even if estimates presented in this article could change for higher or smaller figures, depending on different assumptions, the economic and environmental gains would remain in all cases (unless transmission costs become extremely prohibitive or new, cheap, technologies become available). It is therefore interesting to try to understand which obstacles prevent the better outcome to be obtained. Five obstacles are identified, most likely in decreasing order of importance.

1. Electricity is under provincial jurisdictions. As there is no central leader or coordinator in Canada for electricity markets, no one feels responsible to implement an electricity sector structure that would generate economic and environmental gains in the society.

2. Consumers in regulated provinces want to keep low prices. As market prices would prevail in B.C., Manitoba and Québec, consumers in these provinces would face price increases. This prospect creates high resistance.

3. Electricity producers in market-based provinces want to protect their market share. In Alberta and Ontario, increased trade would directly reduce the market share of current electricity generators, which could only lose in a more integrated market. The irony of this situation is that a Canada-wide competitive electricity market could be blocked by the initial promoters of competition in Canada.

4. Lack of financial environmental rewards. No adequate incentive to reduce GHG emissions exists, as no Federal plan creates economic rewards to export electricity from low-emitting power sources.

5. Possible social opposition to transmission capacity upgrades. As for any new major investment project, resistance of local groups complicates their implementation.

All of these obstacles could be removed with some political will and/or clever economic mechanisms to convince "losers" to accept change in the electricity sector. For instance, direct lump sum payments to electricity consumers in regulated provinces could be made, so that they could directly cash some of the benefits of the new structure (instead of seeing provincially-owned electricity companies suddenly multiplying their profits).

> Trading electricity under market prices would allow CO2-equivalent emissions to be reduced by up to 57,000 kilotons – which would represent almost a third of the Kyoto reduction effort (from 2005 emission levels).
>
> Only reasonable transmission investments are involved in these scenarios.

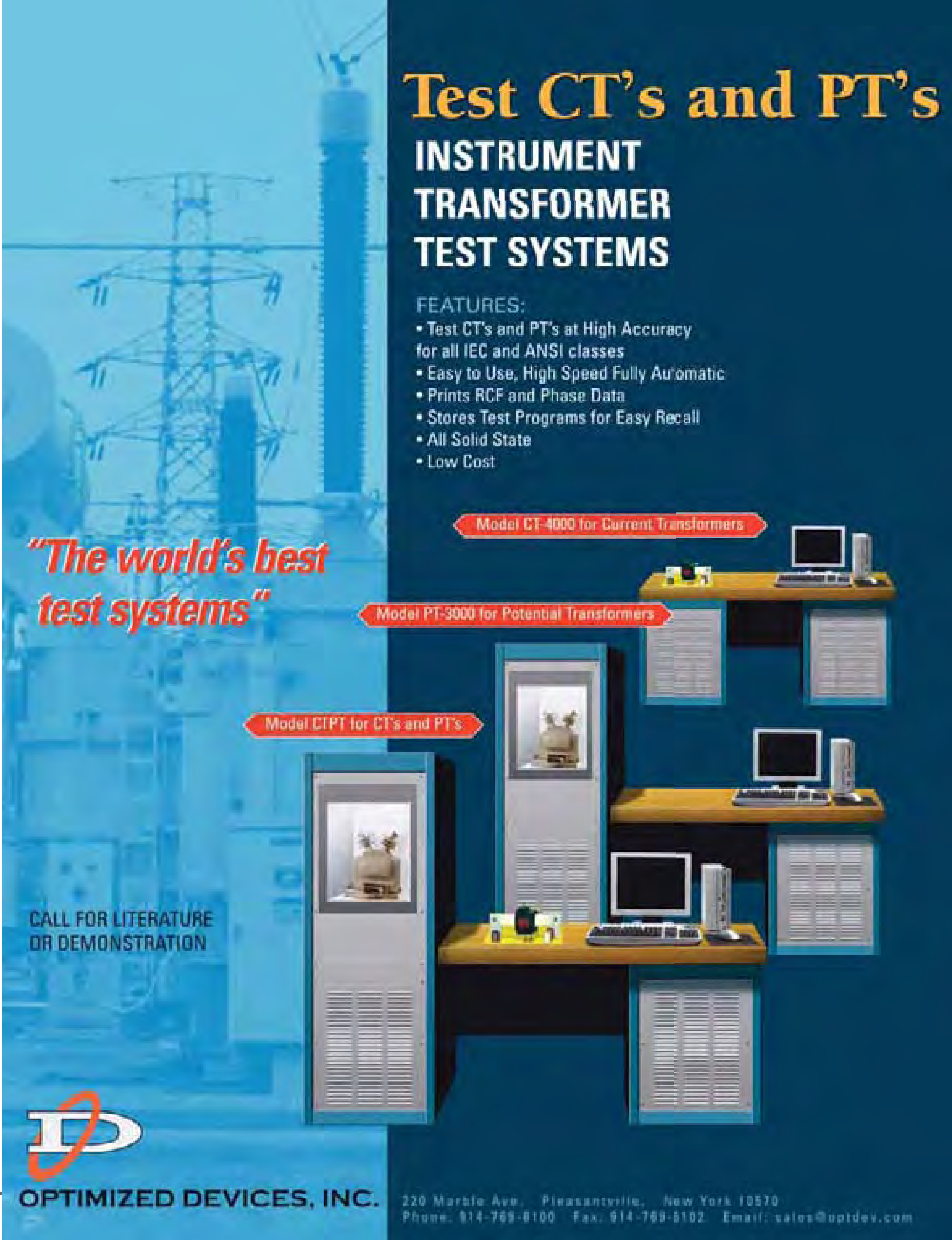
CONCLUSION

Canada is becoming a world leader in energy. Its fossil fuel resources are extremely important and managed under a market system that works – if we ignore the absence of an adequate environmental framework to deal with greenhouse gas emissions. In electricity, market incentives are mostly absent, with a heavy reliance on inefficient average-cost pricing structures. This regulation maintains electricity prices at a low level and creates market distortions preventing significant economic and environmental gains to be made. First, current shareholders of regulated electricity companies do not obtain the full return on their investment because they accept much lower prices than what the market would bare. Second, these economic losses (taking the form of high electricity consumption in regulated provinces) create the need in other provinces to rely on more fossil fuel to generate electricity. Indeed, under a Canadian system where market prices and trade would be used to their full extent, significantly more hydropower could be exported.

The estimate provided in this article for the total loss for shareholders (subsidy to consumers) is about $10 billion per year, before valuing GHG emissions. Trading electricity under market prices would allow CO2-equivalent emissions to be reduced by up to 57,000 kilotons – which would represent almost a third of the Kyoto reduction effort (from 2005 emission levels). Only reasonable transmission investments are involved in these scenarios.

If some important institutional obstacles have been identified, the scope of the benefit is too large to think they are insurmountable. Economic and environmental gains will hopefully be proven once again strong incentives to induce change.

Dr. Pineau is an Associate Professor at the Department of Management Sciences of HEC Montreal. He is an energy policy and management specialist, with a focus on electricity reforms.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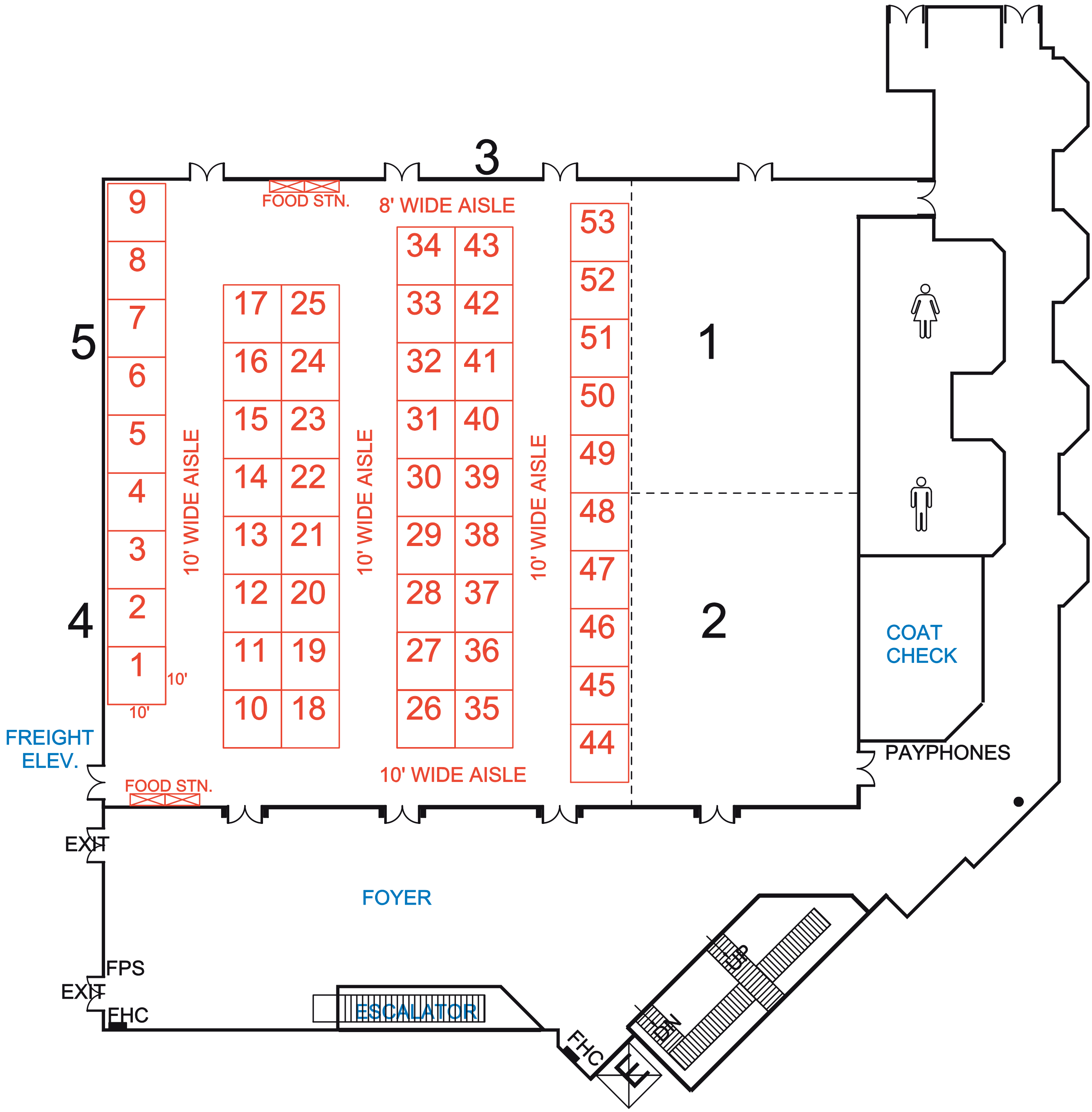

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E-METER WITH PLC-BASED AUTOMATED METER READING

By Markus Pfeiffer, Texas Instruments

For electronic e-meters, there are various ways of transferring data to a concentrator or other device. Nowadays, there are simple techniques to read e-meters from short distances using optical (infrared) or RF links. These technologies still require a utilities official to visit properties where meters are installed. To add value to an electronic e-meter, new ways of communication for AMR are necessary. The first is to read meters remotely to avoid the need for visits. Secondly, functions can be implemented which help to lower cost for the electricity provider, or add new features for end customers. This is possible if the meter is able not only to send, but also to receive data or requests, i.e. via a 2-way communication link.

A wide range of design methodologies already exists for AMR. Most require additional wires or radio links. A completely different technique is power-line communication (PLC), where the power lines, i.e. the mains, are used as the communication media. Despite the fact that PLC has been around for some years, there is as yet no certain standard in relation to AMR. In Europe, nevertheless, there are two major technologies used in this field. IEC 61334, better known by its modulation SFSK, is widely used as well as the Echelon LonWorks CEA709.2 standard. On the other hand, there are a number of proprietary schemes. The major difficulty with PLC is definitively the poor channel quality of the power lines. In order to overcome this problem, high-performance signal processing is inevitable.

To draw a conclusion on the right PLC technology, a highly flexible solution with enough performance at a reasonable price is essential. The ability to integrate all necessary functionality for a complex e-meter with PLC modem into only two chips is a fundamental advantage of a solution provided by new semiconductor devices from Texas Instruments. The TMS320C28xx DSP family offers a powerful performance of up to 150 MIPS to ensure reliable PL-communication, while the MSP430FE42 x MCU devices provide a full e-meter on-chip around its efficient, ultra-low power 16-bit CPU. Hence, a full e-meter with PL-modem consists of only two ICs, current sensors and a small PL-coupling circuit, as shown in figure 1.

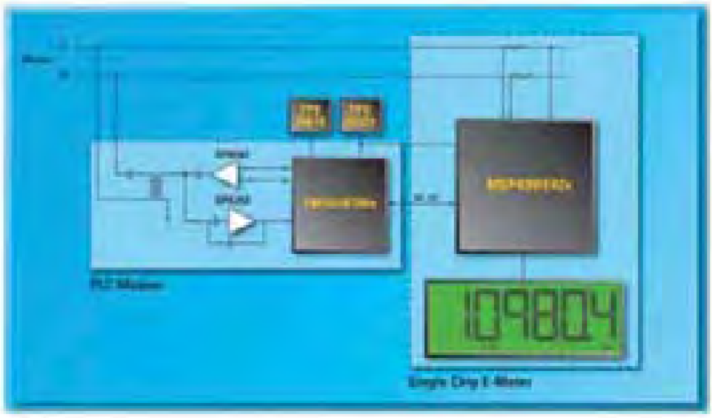


Figure 1. PLC-based AMR dual-chip e-meter solution by TI

The main advantage of a DSP for power-line communication is its flexibility. If a new standard comes up, or in case a utility company wants to use a proprietary technique, the C28xDSPs offer not only high performance, but also internal flash memory. This enables software updates, even in the field. On the other hand, C28x DSPs are available with 100 or 150 MIPS of performance, several memory configurations and are pin-compatible within their sub-families.

Cost is reduced since the same PCB can always be used for different PL-modem types and just the right DSP is chosen, depending on the performance required. The low number of external parts is only possible because of the microcontroller-like peripherals. Intelligent modules offer analog-to-digital conversion and advanced communication (SPI, I2C, and CAN) for a simple and efficient connection to the energy metering chip inside an AMR meter.

The detection of a modulated signal on the mains is made possible by removing the 50/60 Hz power-line voltage at a coupling network.

Secondly, the signal is filtered to extract the carrier. This can be done by a second order active band-pass filter, which is constructed using an operational amplifier. The TI OPA353 is a suitable choice in this application because it features both low-noise voltage performance and low-quiescent current. The filtered signal is then passed directly to one of the channels of the DSP's 12-bit analog-to-digital converter where it is sampled. Once a digital signal is obtained, all further filtering is performed within the DSP. Depending on the type of modulation, the samples are processed, e.g. by FIR or PLL filter structures, to reconstruct the original message. To ensure error-free decoding, cyclic redundancy checks may be performed. While receiving and decoding data is complex, the transmission is fairly simple. To enable error detection or correction at the receiver side, redundancy is added to the data which is about to be sent. Depending on the PLC standard, further bits or words are added for synchronization purposes. The complete data packet is then converted to a tri-level pulse train by two channels of the internal high-resolution pulsewidth-modulator. This signal is passed through a line driver for amplification, which is configured as a low-pass filter to remove unwanted harmonics. A suitable choice for this operation is the TI OPA561, as it is capable of driving high currents into reactive loads. Power-line modems are complex systems due to the poor quality of the communication channel, i.e. the power lines. Texas Instruments offers not just an application note for PLC modems according to the CEA709.2 standard and for SFSK modulation, but also a full software package for both methods free of charge. Data rates of >5 Kbit/s are implemented, but can be increased by changing the code. This software can be used on standard eZdsp developer's boards in junction with a simple analog interface daughter card in order to have a fully functional PL-modem.

This simplifies the initial development and reduces time-to-market. For a cost-effective solution, even the smallest member of the C28xDSP family, the TMS320F2801, can be used for an advanced modem. TI is also a member of the Euridis association, which defines AMR standards based on different media types and certifies AMR products. When mechanical electricity meters were replaced by new electronically controlled versions, a new era of possibilities began. Today it is essential not only to measure the active power consumed. The MSP430FE42x devices feature all peripherals needed for metering functions along with those elements helpful in AMR.

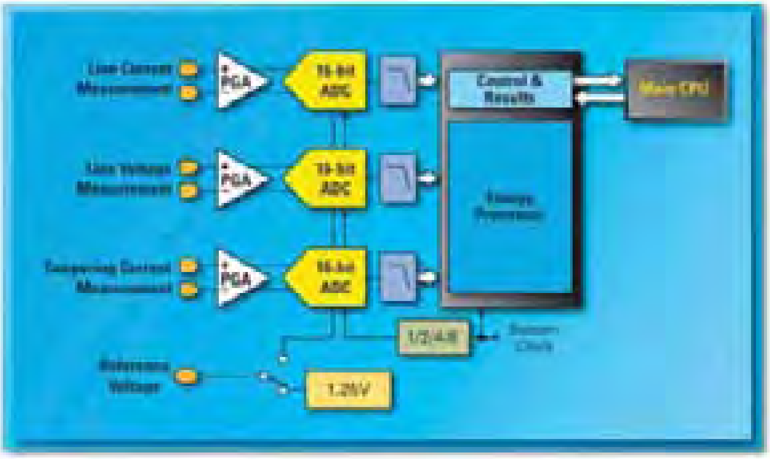


Figure 2. Analog front-end – energy processor and 16-bit SD ADCs together with programmable gain amplifiers

Figure 3. AMR-ready single-phase e-meter with anti-tampering functionality

Of key importance is the analog front-end responsible for accurate energy measurement.

Three separate 16-bit ADCs ensure high resolution and synchronous sampling of current and voltage. Programmable gain amplifiers (PGAs) enable the exact determination of currents over a wide range. The energy processor is essentially a fixed function processor for all tasks related to the actual energy metering. This includes peak and RMS I/V measurements, active, apparent and reactive power calculations, line frequency monitoring and tamper detection.

All this information is made accessible for the CPU though a shared memory architecture which allows simultaneous data access.

In conventional metering devices, the CPU within the microcontroller is responsible for controlling the analog front-end and making all energy calculations. By integrating the energy processor, the CPU is offloaded by the analog front-end control to provide more bandwidth for higher-level display and especially AMR functionality. The analog front-end measures currents in junction with shunt resistors, current transformers or Rogowski coils. The line voltage is measured directly via a simple resistor divider. Bipolar voltage measurement is a key feature of the analog front-end and makes the meter design easier.

The third input channel offers to install additional tamper detection for single-phase electricity meters. To save cost, typically a shunt resistor is used to monitor the current on the neutral line looking for deviations compared to the line current. This is illustrated by a block diagram in figure 3. Because of the high integration level of both analog and digital functionality – such as multiple 16-bit sigma-delta ADCs and PGAs – a dedicated energy processing engine and ultra-low power 16-bit RISC CPU, the MSP430FE42x offers the possibility to have an advanced e-meter with a minimum of external components. Its flexible communication peripherals offer efficient connectivity to modern AMR modules like PLC modems.

Hence, the MSP430FE42x can be connected directly to a TMS320C28x DSP using a standard SPI link. As a result, an advanced, highly flexible and precise e-meter with PLC-based AMR needs to consist of only two chips with a minimum amount of external components.

THE BUSINESS CASE FOR AUTOMATED METERING CASH FLOW BENEFITS

Cash is king. Beginning in the 1980s and growing in the 1990s, U.S. business is increasingly driven by cash flow. In many cases, Wall Street values companies not by profitability, but by cash flow. AT&T paid $12 billion for McCaw Communications — which had not made a profit for many years. What McCaw did do – and this is why AT&T bought McCaw – is generate a lot of cash.

What does all this have to do with automatic meter reading? Plenty.

As utilities face greater competition, there is pressure to conserve cash and to find better places to invest cash. Many utilities are avoiding investing capital in their regulated business, because the return on investment is limited on the upside. At the same time, with competition, there is greater risk on the downside.

The reason automated metering is important in this picture is that automation offers utilities opportunities to improve cash flow and save potentially several hundred million dollars in interest expenses. Investor owned electric utilities — which serve 76.4% of U.S. customers — paid an average cost of capital of 9.55% more than $21 billion in outstanding accounts receivable from customers. The result is annual expenses of $2 billion! This works out to an average of $2 per month, on average, for every electric utility customer.

Savings through Advanced Metering

Automated metering can reduce this annual expenditure, potentially significantly, by shortening the time between meter reading and bill issuance. Before we get to the savings, let's review how this works in a little bit more detail. When a utility reads a meter, it, in essence, has completed delivery of a service called "one-month's worth of electricity." Since delivery is completed, the utility is now entitled to record the value of that service as revenues on its books. However, the cash payment is not received at the same time, as it would be if you were buying milk at the grocery store.

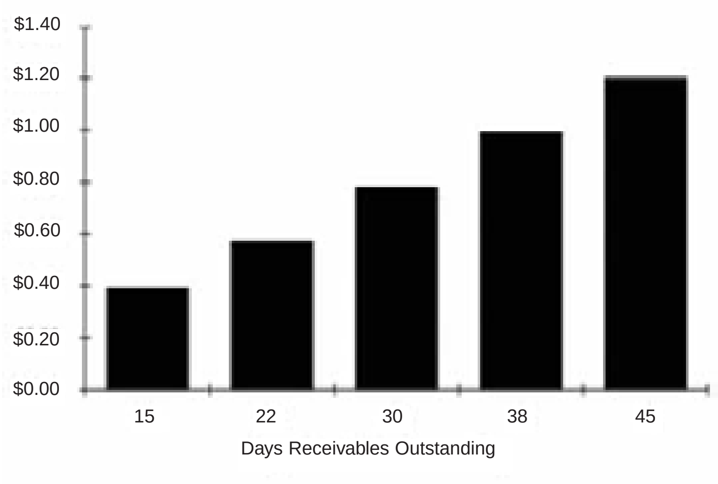
Because the utility does not receive the cash right away, it cannot use the customer's dollar to pay for something else that the utility must pay for right away — for example, salaries of utility employees. To bridge the gap until the customer's dollar is received, the utility borrows money in the form of debt, from banks or others, or equity, through selling stock. This creates the need to pay interest, or stock dividends, on the amount borrowed. The result, to summarize, is that the customer's delay in paying the utility (measured from the time the meter is read to the time the cash or check is received by the utility) results in the interest expense referred to above. The utility records the amount of money financed for this purpose on its balance sheet in a category called Accounts Receivable. This is the $21 billion amount mentioned earlier. If there were no delay between meter reading and cash collection, utilities would immediately have $21 billion in cash to pay for salaries and other costs, thus avoiding the need to borrow that amount.

The average delay between meter reading and cash receipt can be calculated from a utility's balance sheet by dividing the Accounts Receivable amount by total annual revenues and multiplying by 365. Since U.S. investor-owned utilities had $175 billion in revenues in 1993, the average delay, also called "Days Receivables Outstanding," was 29.5 days.

Many utilities have 22 or 23 days receivables outstanding, while at least one major utility has 46 days. The effect of the number of days receivables outstanding is dramatic. The chart below shows the difference between the 46-day utility and the potential for, say, a 15-day utility in dollars per customer per month, for a customer with a $100 monthly bill.

Interest Cost of Different Delay Periods between Reading Meters and Receiving Cash

Through advanced metering — sometimes called "fixed-network" automatic meter reading — utilities have a number of ways that the number of days receivables outstanding



Source: Energy Information Administration, U.S. Department of Energy

can be reduced. The first way to speed up cash collection is by shortening the period between meter reading and bill mailing. The best way to do this is to read the meter automatically right after midnight and immediately deliver the data to the billing system. The billing system can then calculate and print bills that morning. By afternoon, the bills can be mailed to customers.

This approach would speed bill issuance for most utilities by about three days. This is for a couple of reasons. The first is that manual reads are delivered to the billing system late in the day, so the best-case seenario is to process and mail bills by the next day. Moreover, most utilities wait until full meter reading routes are completed, including up to three days after the scheduled read date to allow meter readers flexibility or a second chance to pick up missed reads. Only after the full routes are delivered are the reads sent to billing.

The second way to speed cash collection is by offering additional services to customers in the form of electronic funds transfer from a bank account. Some utilities do this already. However, most customers do not sign up because they want to pick the day of the month that the funds are transferred. Since meter reads must be on the scheduled date, utilities have great difficulty allowing customers the day of the month they can have funds transferred. With automated metering, the meter can be read any day of the month. So, by combining the ability to select the day of the month with the service of electronic funds transfer — which saves the customer having to write a cheque and pay for a stamp — utilities are likely to have many more customers sign up for electronic funds transfer.

The result can be dramatic. Let's use the average days receivable of 29.5 days as the starting point. For electronic funds transfer customers, the delay between the day of the meter read and the cash receipt drops to one day (to allow for processing). If only 20 percent of customers sign up for electronic funds transfer, the savings is (29.5 days - 1 day) x 20 percent, which equals 5.7 days, a 19.3 percent reduction in the average days receivables outstanding. Using an average cost of $1.35 per customer per month, the savings in this example totals a sizable $0.26 per customer per month. And that's for only 20 percent participation.

The third way to speed cash collection is electronic funds transfer using an in-home or in-building communications device. The customer would use this device to receive their bill from the utility electronically and then, using a Personal Identification Number, would electronically authorize payment of the bill.

This would further increase market acceptance of electronic funds transfer, because other energy services and information would be available to the customer: energy rates, monthly bill to date, outage notices, weather data, and other value-added information. If these many benefits increased market acceptance of electronic funds transfer by another 30 percent, the total savings — when combined with the 20 percent acceptance above — reaches $0.67 per customer per month.

CONCLUSION

During the 1990s and beyond, cash flow is a major driver for utilities and other businesses. Through a variety of mechanisms, automated metering offers a powerful tool to improve cash flow and speed receipt of cash from customers. The magnitude of the savings can exceed even the savings realized by replacing manual meter readers.

Though just one example of many savings opportunities, cash flow illustrates the powerful, strategic benefits of automated metering. Reading meters is just the start. The real benefits, like cash flow, go far beyond.

UTILITY WIRELESS COLLOCATION IS GROWING; SO ARE CONCERNS ABOUT RISKS

Wireless collocation on electric utility assets has grown more than 20% over the past two years, according to a recent survey completed by the Utilities Telecom Council (UTC).

Some utilities see collocation as a significant revenue opportunity, but the UTC survey found that the most important factors affecting utility decisions to allow wireless attachments are the safety, regulatory, engineering, and business risks associated with collocation.

The Federal Communications Commission (FCC) has authority in many states over the distribution infrastructure of investor-owned utilities (IOUs) for the purposes of pole attachments, including wireless attachments.

IOUs, municipal and co-operative utilities, however, may be subject to state collocation laws, resulting in a broad variety of regulations, and corresponding utility business and risk mitigation models across the U.S.

UTC conducted a survey of utilities, as well as in-depth interviews with utility managers, to create its new Wireless Attachment Market Report. The report discusses trends in the wireless collocation market, and outlines some of the business and risk mitigation tactics that utilities are using as their wireless collocation strategies evolve, including:

• Some utilities are creating separate asset management businesses for attachments;

• Other utilities are building special towers near electric substations to provide collocation, while others are building poles and lines exclusively for wireless services;

• Utilities reported that the majority of wireless attachments are intended for Internet access services, for which regulations allow utilities to negotiate market-based rates.

"The growth of wireless services, and carriers' need for siting, create important business implications for utilities," said William R. Moroney, UTC President and CEO.

"Utilities that are able to properly handle the regulatory and business aspects of wireless collocation may be able to create successful business models that also benefit the communities the utilities serve."

VOLTAGE SAGS: AN EXPLANATION - CAUSES, EFFECTS AND CORRECTION - PART I

By Ian K.P. Ross, MIEE, Omniverter Inc.

1.0 VOLTAGE SAG DEFINITION

1.1 Voltage Sag

A voltage sag as defined by IEEE Standard 1159-1995, IEEE Recommended Practice for Monitoring Electric Power Quality, is a decrease in RMS voltage at the power frequency for durations from 0.5 cycles to 1 minute, reported as the remaining voltage.

The measurement of a voltage sag is stated as a percentage of the nominal voltage, it is a measurement of the remaining voltage and is stated as a sag to a percentage value. Thus a voltage sag to 60% is equivalent to 60% of nominal voltage, or 288 volts for a nominal 480 Volt system.

1.2 Voltage Dip

In North America a voltage dip is usually understood to mean the amount by which the nominal voltage declines - in

Voltage Sag - A reduced voltage for a limited period
Figure 1

percentage terms this, is 100-voltage sag. Thus, a voltage dip of 40% equates to a voltage sag to 60%.

Unfortunately in practice there is confusion, and the terms voltage sag and voltage dip are sometimes interchanged. It is therefore important that data is clarified.

2.0 WHERE DO VOLTAGE SAGS OCCUR?

2.1 Utility Systems

Voltage sags can occur on utility systems both at distribution voltages and transmission voltages. Voltage sags that occur at higher voltages will normally spread through a utility system and will be transmitted to lower voltage systems via transformers.

2.2 Inside Industrial Plants

Voltage sags can be created within an industrial complex without any influence from the utility system. These sags are typically caused by starting large motors or by electrical faults inside the facility.

3.0 CAUSES OF VOLTAGE SAGS

3.1 Utility Systems

3.1.1 Operation of Reclosers and Circuit breakers

If, for any reason, a sub-station circuit breaker or a recloser is tripped, then the line that it is feeding will be temporarily disconnected. All other feeder lines from the same substation system will see this disconnection event as a voltage sag which will spread to consumers on these other lines (See Fig.2). The depth of the voltage sag at the consumer's site will vary depending on the supply line voltage and the distance from the fault. Typically, a higher supply voltage will have a larger sag affected zone.

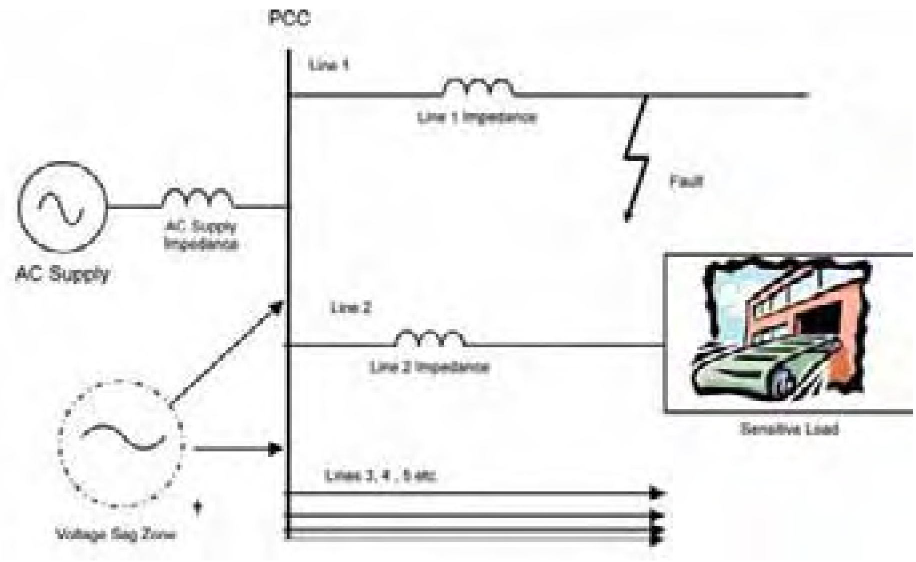


Figure 2

3.1.2 Equipment Failure

If electrical equipment fails due to overloading, cable faults etc., protective equipment will operate at the sub-station and voltage sags will be seen on other feeder lines across the utility system.

3.1.3 Bad Weather

Thunderstorms and lightning strikes cause a significant number of voltage sags. If lightning strikes a power line and continues to ground, this creates a line-to-ground fault. The line-to-ground fault in turn creates a voltage sag and this reduced voltage can be seen over a wide area. Note the lightning strike to ground causes voltage sags on all other lines (See Fig 2). Circuit breakers and reclosers operate more frequently in poor weather conditions:

• High winds can blow tree branches into power lines. As the tree branch strikes the line, a line-to-ground fault occurs which creates a voltage sag. If the line protection system does not operate immediately, a series of sags will occur if the branch repeatedly touches the power line. Broken branches landing on power lines cause phase-to-phase and phase-to-ground faults.

• Snow and ice build-up on power line insulators can cause flash-over, either phase-to-ground or phase-to-phase. Similarly, snow or ice falling from one line can cause it to rebound and strike another line. These events cause voltage sags to spread through other feeders on the system.

3.1.4 Pollution

Salt spray build-up on power line insulators over time in coastal areas, even many miles inland, can cause flashover, especially in stormy weather. Dust in arid inland areas can cause similar problems. As circuit protector devices operate, voltage sags appear on other feeders.

3.1.5 Animals & Birds

Animals, particularly squirrels, raccoons and snakes occasionally find there way onto power lines or transformers and can cause a short circuit either phase-to-phase or phase-to-ground. Large birds, geese and swans, fly into power lines and cause similar faults. While the creature rarely survives, the protective circuit breaker operates and a voltage sag is created on other feeders.

3.1.6 Vehicle Problems

Utility power lines frequently run alongside public roads. Vehicles occasionally collide with utility poles causing lines to touch, protective devices trip and voltage sags occur.

3.1.7 Construction Activity

Even when all power lines are underground, digging foundations for new building construction can result in damage to underground power lines and create voltage sags.

3.2 Industrial Plants

Voltage sags can be caused within an industrial facility or a group of facilities by the starting of large electric motors either individually or in groups. The large current inrush on starting can cause voltage sags in the local or adjacent areas even if the utility line voltage remains at a constant nominal value.

4.0 MULTI-PHASE SAGS AND SINGLE-PHASE SAGS

4.1 Single-Phase Sags

The most common voltage sags, over 70%, are single-phase events which are typically due to a phase-to-ground fault occurring somewhere on the system. This phase-to-ground fault appears as a single phase voltage sag on other feeders from the same substation. Typical causes are lightning strikes, tree branches, animal contact etc. It is not uncommon to see single-phase voltage sags to 30% of nominal voltage or even lower in industrial plants.

4.2 Phase-to-Phase Sags

Two-phase, phase-to-phase sags may be caused by tree branches, adverse weather, animals or vehicle collision with utility poles. The two-phase voltage sag will typically appear on other feeders from the same substation.

4.3 3 Phase Sags

Symmetrical three-phase sags account for less than 20% of all sag events and are caused either by switching or tripping of a three-phase circuit breaker, switch or recloser which will create a three-phase voltage sag on other lines fed from the same substation.

Three-phase sags will also be caused by starting large motors, but this type of event typically causes voltage sags to approximately 80% of nominal voltage and are usually confined to an industrial plant or its immediate neighbours.

5.0 VOLTAGE SAGS AFFECT PRODUCTION

Both single-phase and multi-phase voltage sags can cause unplanned production stoppages but single-phase (120V) control devices and electronic sensors can be very vulnerable to voltage sags.

Modern electronic equipment requires more precise voltage regulation than traditional devices such as induction motors. When the manufacturing industry used mechanical devices and gearboxes to control the speed of its processes, many of which were relatively slow and required manual operation or intervention by operators, voltage variations were not such a serious issue.

Automation has lead to high speed processes, automatic electronic sensing and controls; precision machine tools have sophisticated electronic controls, variable speed drives have replaced many gearboxes and any unplanned manufacturing stoppage can be very expensive.

Electronic process controls, sensors, computer controls, PLCs and variable speed drives, even conventional electrical relays are all to some degree susceptible to voltage sags. In many cases, one or more of these devices may trip if there is a voltage sag to less than 90% of nominal voltage, even if the duration is only for one or two cycles i.e. less than 100 milliseconds.

The time to restart production after such an unplanned stoppage can typically be measured in minutes, hours or even days. Costs per event can be many tens of thousands of dollars.

5.1 Cost Of Voltage Sags

A recent EPRI study (Ref 2) suggests that the cost to North American industry of production stoppages caused by voltage sags now exceeds US$250 billion per annum.

6.0 WHO IS TO BLAME?

Frequently, industrial customers blame their local electrical supply utility for unplanned production stoppages and claim that other jurisdictions have "much better power quality".

Unfortunately, in many cases there is little or nothing the utility can do. It is true that certain parts of North America experience more storms than others, so voltage sags are more prevalent in some areas.

Even in desert areas devoid of trees, storms and lightning strikes occur. Given the large distances between power plants and consumers in North America, the cost of underground conductors at all voltages would be prohibitive, even if underground rights-of-way were available. Few consumers would wish to see their utility power bill increase several fold in order to pay for this.

Very few utilities, anywhere in the world, escape voltage sags. Even those with total underground systems in a small geographic area such as Singapore suffer voltage sags. These may be due to damage to cables by digging for new construction or due to failure of electrical equipment from cable faults, overloads etc.

7.0 INDUSTRIAL RESPONSIBILITY

Industrial customers who have invested heavily in production equipment which is susceptible to voltage sags must take responsibility for their own solutions to voltage sags or lose some benefit from their investment.

Voltage sags are a fact of life – they cannot readily be eliminated from regular utility systems.

For the industrial customer the solution may involve replacement of components or devices, which are especially sensitive, with less voltage sensitive substitutes or installation of some form of protection against voltage sags.

8.0 THE SOLUTION

8.1 First Identify the Problem

8.1.1 Equipment Identification

In order to provide an optimal and cost effective solution to voltage sag problems, it is necessary to determine which equipment is susceptible to unplanned stoppages. In most industries, there is still a significant amount of electrical equipment which is not sensitive to voltage variation or which can be restarted at little or no cost. Usually it is not necessary to protect an entire industrial facility, it is sufficient to protect the key sensitive equipment.

8.1.2 Identify the Voltage Sags

The next stage is to determine the frequency, depth and duration of the voltage sags.

These can vary widely even in apparently similar industrial facilities. Collection of this data is essential if the optimal solution is to be identified.

In North America, only a small proportion of manufacturing businesses have installed electrical metering which is capable of measuring and recording the voltage variations which are responsible for the majority of their very costly Unplanned Production Stoppages.

Look in the January/February issue for the conclusion of this article

STATE-OF-THE-ART COMBUSTION CONTROLS CO2 EMISSIONS FROM COAL - PART II

By H. Farzan, S. Vecci, D. McDonald and K. McCauley, The Babcock & Wilcox Company
P. Pranda, R.Varagani, F. Gautier, J.P. Tranier and N. Perrin, Air Liquide

The goal that management sets, and the way that goal is measured, can make a difference in the operation of a power plant. Many comparisons of generating technologies use the “Cost of Electricity” (COE) as the best way to compare different generating technologies. B&W often works with the owners of the power plants, who are in the business of generating electricity.

For these owners, “Cost of Electricity” is only part of their objective.

Whether or not the power plant is subject to price regulation, the owners aim to recover their full costs, including the cost of capital. The owners also aim to make an economic profit, in addition to covering their costs. B&W’s customers often judge the success of a power plant by whether it provides a positive Net Present Value (NPV) and whether the project’s Internal Rate of Return (IRR) meets their goals for such a large capital investment.

For estimates of the price of electricity and the cost of fuels, the writers used recent studies from the U.S. Department of Energy, including the supplemental regional forecasts from the Energy Information Administration’s Annual Energy Outlook 2006, to define the business environment in four representative regions of the country, to the year 2030.

The various technologies for carbon management are mixed in their rankings (far right column in dollars) on Net Present Value in Table 4 (rank column refers to IRR results). No one combustion technology appears to dominate the returns at this early stage of development, and gasification currently is the least attractive due to a higher capital cost and lower availability. Based on what is known now, it is appropriate to invest in research and development for a range of technologies for carbon management of coal.

If a power company were to invest in a new plant with expensive carbon management, while none of the other power companies did, then the low-carbon investor would also have a higher price of electricity for sale to the grid. As a result, that low-carbon plant would be dispatched less often. Power companies are not as likely to invest in carbon management technologies until there is assurance that competing power companies will also invest in carbon management technologies, or until incentives encourage it.

Table 4 Economic Comparison of Technologies
Net Present Value (NPV) equity financed, 30-year service life

Rank	Case	Description	$000s
1	1	Conventional Supercritical w/out Carbon Management	839,545
2	2	IGCC without Carbon Management	265,742
4	7	Ultra Supercritical with Oxy-Fuel (95% O_2)	227,674
3	11	Supercritical with CO_2 Scrubber AC	212,651
6	8	Ultra Supercritical with Oxy-Fuel (EOR quality)	175,609
7	4	Conventional Supercritical with Oxy-Fuel (95% O_2)	(12,594)
8	5	Conventional Supercritical with Oxy-Fuel (99% O_2)	(24,084)
9	6	Conventional Supercritical with Oxy-Fuel (EOR quality)	(24,795)
10	10	Supercritical with CO_2 Scrubber KS-1	(27,789)
5	3	IGCC with Carbon Management (Achieved Availability)	(124,697)
11	9	Supercritical with CO_2 Scrubber MEA	(595,524)

However, some power companies are pursuing programs, which include carbon management.

A few are well located, to provide carbon dioxide for enhanced oil recovery (EOR). Others intend to master the technology of carbon management, in preparation for the time when that may be a key competitive competence.

OXYGEN PRODUCTION AND CO2 TREATMENT

The following section describes key elements of the overall oxy-coal combustion feasibility and competitiveness. They relate to O2 production and CO2 treatment developed and provided by AL and resulting from its historical technology focus on applications developed for more than a century.

Oxygen production

Technology

For the quantities required by oxy-coal combustion in a commercial scale plant (several thousand metric tons of oxygen), the only available technology today is cryogenic distillation.

Other available technologies for air separation like pressure swing adsorption (PSA), vacuum swing adsorption (VSA) or polymeric membranes cannot compete economically for such quantities and also in terms of achievable oxygen purity (above 95%). Ceramic membranes (oxygen ion transport membranes) are not yet available for such quantities and therefore it is still hard to compare them to cryogenic distillation both in terms of investment and performance.

Specification for oxy-coal combustion

The main characteristics of the ASU for oxy-coal combustion are: large size (typically beyond 8000 tpd for industrial-scale plants), low pressure (between 1.3 and 1.7 bar abs) and possible low oxygen purity. Low oxygen purity means a value in the range of 95-98% O2 content compared to the typical 99.5-99.6% O2 content of the high purity content normalized to 100 in energy scale. This allows significant savings in power consumption in the ASU as shown in Figure 4.

The key parameter in the optimization of an ASU is the trade-off between capital expenses (CAPEX) and operation expenses (OPEX). In other words, the question is: how much am I ready to invest (CAPEX) in order to save power consumption (OPEX) for the ASU? This depends primarily on the cost of power.

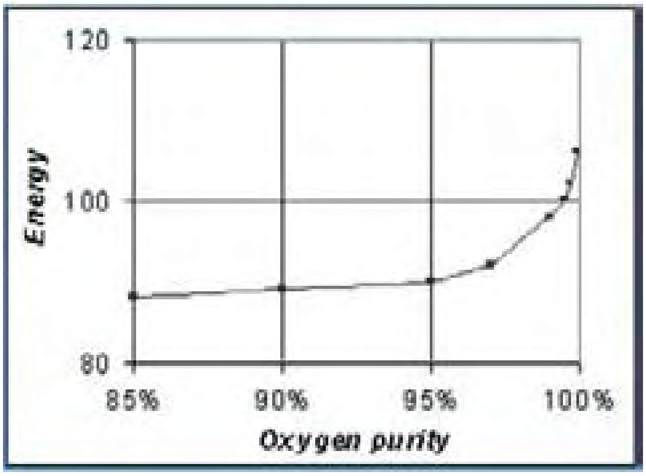


Fig. 4 Air separation unit (ASU) power requirement.

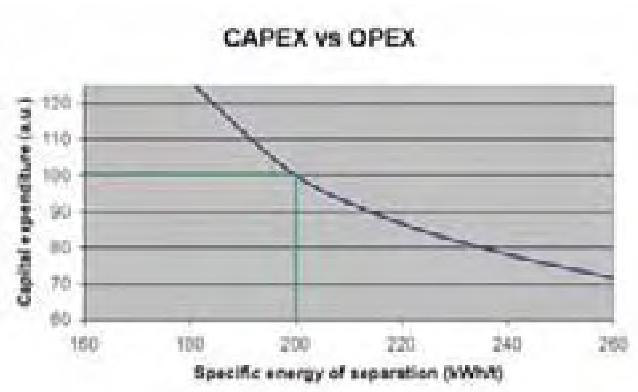


Fig. 5 Trade-off of CAPEX and OPEX in ASU design.

Figure 5 illustrates the flexibility in the design of an ASU in terms of trade-off CAPEX vs OPEX. This typical curve shows that by increasing by 25% the capital expenditure, it could be possible to decrease by 10% the power consumption of the ASU (for example from a specific energy of separation of 200 kWh/metric ton) or to decrease the capital expenditure by 15% by increasing the power consumption by 10%.

Process scheme

An ASU consists of the following equipment:

- air compressor
- precooling system
- purification unit to remove water and CO_2 prior to entering the cryogenic section
- heat exchangers
- distillation column

Up to 5000 metric tons/day, AL proposes a process scheme with a double column dual vaporizer scheme with no duplication of equipment: one purification unit for water and CO_2 removal with its proprietary radial bed design, one high pressure (HP) column and one low pressure (LP) column

CO_2 COMPRESSION AND PURIFICATION UNIT (CPU)

Technology

For oxy-coal combustion plants, the best solution to purify the flue gas coming from the boiler is a low temperature (around -56C) partial condensation scheme as soon as O_2 removal is considered.

Specification for oxy-coal combustion

The CO_2 specification is one of the main topics to be addressed in order to design the CO_2 CPU. It depends on the application: enhanced oil recovery (EOR), saline aquifer, or enhanced coal bed methane (ECBM). However, other considerations such as transport specifications and regulations may have an impact on the CO_2 specification.

Process scheme

Low pressure flue gas from the boiler is compressed to a typical pressure of 30 bar abs, precooled and dried. It then enters a “cryogenic” section where it will be partially condensed in one or several steps to obtain a product enriched in CO_2 and a non-condensable stream containing N_2, Ar and O_2. A distillation column can be added to have a product with a lower O_2 content. The product enriched in CO_2 is further compressed, condensed and pumped to a supercritical pressure (typically between 100 and 200 bar abs).

OXY-COAL COMBUSTION FOR RETROFITTING COAL-FIRED BOILERS

After determining the technical and economic barriers of the oxy-combustion technology, the following two projects were initiated: 1) significantly broaden the scope of the technology to different coal ranks and boiler types, and 2) scale-up the technology. The former is discussed below and the latter will be discussed in the section titled CEDF oxy-coal combustion campaign.

Under sponsorship of the U.S. DOE, B&W and AL will further develop the oxy-coal combustion technology for commercial retrofits in wall-fired and Cyclone boilers. As it was explained before, previous development efforts have been performed with an eastern bituminous coal and a sub-bituminous coal. This project expands the applicability of the technology to lignite firing; in addition, oxy-coal combustion will be adapted in this program for application to Cyclone-equipped boilers.

Upon successful completion of this development effort, pilot-scale oxy-coal combustion test data will be available for application and scale-up to both wall-fired and Cyclone boilers that burn bituminous, sub-bituminous or lignite coal. This project significantly broadens applicability of oxy-coal combustion technology to the existing fleet of coal-fired boilers. Our approach to expand the applicability of the technology is:

- To perform pilot-scale R&D, both wall-firing and Cyclone
- To develop specifications for storage, transportation, and compression train, and to minimize the equipment required for emissions control, CO_2 capture, and storage
- To further reduce the increase in cost of electricity through system integration
- To perform an engineering and economic evaluation for a wall-fired and a Cyclone boiler to assess the impact of oxy-coal combustion on electric generation cost

The tests will be conducted in a new 1.8 MWth facility. The Small Boiler Simulator (SBS-II), illustrated in Figures 6 and 7, is a combustion and fuel handling facility that allows B&W to evaluate various fossil fuels, combustion processes, emission control devices, and associated hardware for potential commercial use. The 1.8 MWth (6 MBtu/hr) vertical furnace of the SBS simulates the geometry of front-wall fired commercial boilers. With waterwall construction and insulation, it yields gas temperatures and residence times representative of commercial units.

The unit will be fired by a scale model of B&W’s commercial low-NOx burner (DRB-4Z®). This allows B&W to examine flame shape and stability, flame temperature, and staged combustion with low-NOx burners and overfire oxidant (OFO) to ensure the pilot facility is operating similar to commercial coal-fired boilers. Pulverized coal is prepared offline to the same fineness as commercial boilers (usually 70 %< 200 mesh) and transported by a weigh belt feeder for indirect firing applications. The convection pass design produces a flue gas time/temperature history that is representative of commercial boilers. The facility is equipped with a baghouse, dry or wet scrubber, and a condensing heat exchanger.

The facility is currently under construction at the newly relocated Babcock & Wilcox Research Center (BWRC) located at the B&W main campus. AL will relocate their 9,000-gallon (34,000 liters) liquid oxygen tank and its oxygen control skids to the new location.

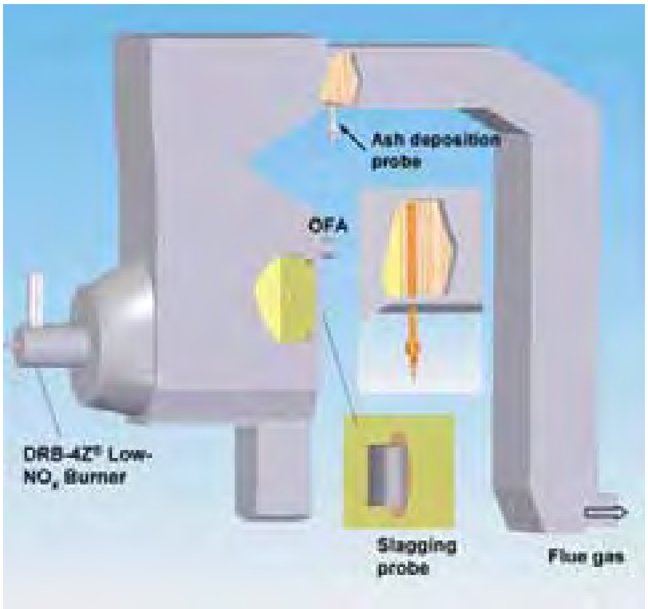


Fig. 6 B&W 1.8 MWth small boiler simulator (SBS) II.

CEDF OXY-COAL COMBUSTION CAMPAIGN

As discussed earlier, scale-up of the oxy-combustion burner was one of the technical barriers that will be discussed here. The largest test facility in the world that has operated under oxy-coal combustion conditions with pulverized coal is in Ohio, U.S.A. Others are proposing test facilities including the 30 MWth Vattenfall project in Germany and the 30 MWe Callide project in Australia. With the need to support design of commercial scale projects, B&W and AL decided in late 2006 to convert B&W’s existing 30 MWth Clean Environment Development Facility (CEDF) in Alliance, Ohio to an oxy-coal combustion system.

The objective of this project is to demonstrate oxy-coal combustion technology at 30 MWth. The project will demon-

Continued on Page 44

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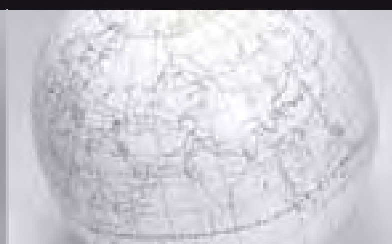

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strate the following main elements:

• Near-full-scale burner fed directly by an on-line pulverizer

• Pulverizer performance is affected by flue gas composition

• Pulverizer may require more recycle gas than air to maintain acceptable performance, especially with low-rank coals

• New burner designs to be evaluated for various coals

• Three coals will be tested: lignite, sub-bituminous, and eastern bituminous

• Will demonstrate B&W's novel concept for controlling flue gas moisture content via a wet scrubber with integrated cooling

• Support the commercial project development that will be explained below A test campaign will be conducted in summer 2007.

DEVELOPING A 300 MWE COMMERCIAL OXY-COAL BOILER

During the next 20 to 30 years, Saskatchewan Power Corporation Inc. (SaskPower), Saskatchewan, Canada, will be making major decisions concerning the refurbishment or replacement of virtually its entire fleet. Saskatchewan's 300-year supply of mineable lignite coal remains the most cost-efficient and stable-priced fuel for base load generation but there are environmental concerns.

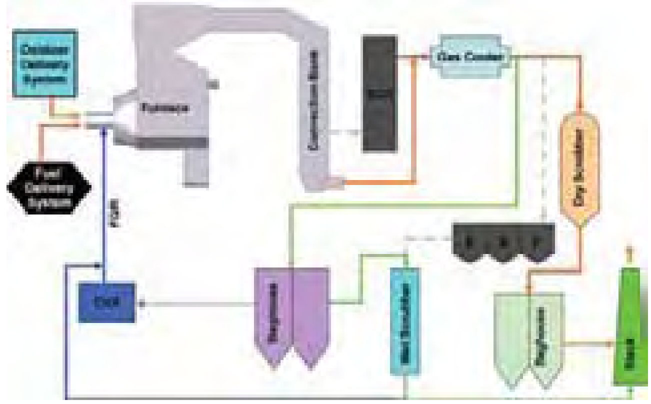

Fig. 7 SBS-II general layout.

For several years, SaskPower has been involved in evaluation of technologies for carbon dioxide management in coal-fired power plants. Recently, they announced a Clean Coal Project development that will capture over 90% of the carbon dioxide produced from coal combustion. This project would result in a power plant that not only produces 300 net megawatts (MWe) of electricity but also will capture 8,000 tons of CO_2 per day to extract more oil from Saskatchewan oil fields through enhanced oil recovery (EOR). Additional emissions-control technologies will also be incorporated, bringing the Clean Coal Project to near zero emission plant (NZEP) status.

After evaluation of the technology options and selection of oxy-coal, SaskPower, Babcock & Wilcox Canada (B&W) and AL came to an agreement in late 2006 to jointly develop oxy-coal technology as the core process for the unit to be located at the Shand facility near Estevan, SK, Canada. Figure 8 shows an artist's rendering of the future oxy-coal combustion plant at Shand. Marubeni Canada and Hitachi will supply the turbine generator set. The oxy-coal technology nearly eliminates emissions of combustion by-products, including greenhouse gas emissions, and may be the world's first near zero emissions (NZEP) pulverized coal unit.

Fig. 8 Artistic rendering of oxy-combustion plant at Shand.

In deciding on oxy-coal, SaskPower thoroughly examined and researched both oxy-coal and the post-combustion cleanup processes. Based on the current state of both technologies and project-specific parameters, they selected oxy-coal and expect it to provide the best environmental performance and lowest cost.

In 2006 SaskPower, B&W, and AL came to an agreement to develop the plant with B&W supplying a system based on a supercritical boiler and AL providing the air separation plant and CO_2 compression system. Significant design work and costing is underway to assess whether SaskPower should proceed to the construction phase. That decision is expected soon to support an in-service date in 2011.

When successful, this power plant will be the first of its kind in a utility scale application. In support of this effort, B&W has also decided to convert its existing 30 MWth Clean Environment Development Facility (CEDF) located in Alliance, Ohio for oxy-coal testing.

SUMMARY

The ability to capture CO_2 from power plants is feasible in advanced modes of current technology and with new technologies under development with significant industry-driven R&D underway. Technologies are not decades away, but are some number of years away and can support a regulatory process that meets carbon management objectives.

As an industry, we have been and will continue to work hard to absorb and analyze the impact of GHG stabilization policy on the power generating industry and deliver timely, effective and economic solutions.

B&W has been designing and supplying steam generating systems for electric power generation for more than 140 years. B&W continues to advance the technology in ultra-supercritical boiler applications and advanced environmental emission controls meeting the requirements of today and into the future.

Over the previous few decades, B&W has developed many new environmental control technologies and helped the power generation industry to significantly reduce its NOx, SO_2 and particulate matter from coal-fired boilers. Our current R&D efforts on oxy-combustion as well as other post-combustion technologies are enabling us to provide utility boiler operators a solution when CO_2 emissions are regulated. B&W is confident that with our new development efforts, PC boilers will operate in an environmentally friendly manner in a carbon constrained world.

Further, economic evaluation carried out by AL, B&W and the DOE indicates that oxy-combustion is an economically viable technology for retrofitting existing boilers as well as new pulverized coal boilers. Supercritical boilers have proven reliability and show a promise of much higher efficiency when they are used in ultra-supercritical steam cycle conditions. B&W believes that the combination of proven reliability, higher efficiency and ultra low emission of NOx, SO_2 and particulate matter provide us with a base technology that we should pursue for carbon capture (along with other newer technologies).

Oxy-combustion technology requires introducing some new equipment such as the ASU and the CO_2 CPU to power plants. AL has designed the largest ASU which is operated at a capacity of 4000 tons/day of oxygen and is currently offering plants of capacities around 5000 metric tons/day. A single industrial site exists with cumulative oxygen production of approximately 40,000 metric tons/day. Studies have also been performed for an air separation unit of 7000 metric tons/day.

SMART METER USERS GIVE A THUMBS UP

By Don Horne

The final numbers are in from the Ontario Energy Board's (OEB) Smart Price Pilot, and the consensus is that people like to have control over how much and when they use their electricity.

"In many cases the savings were small for those using the smart meters, but they did appreciate having their metering bills in greater detail," says James Strapp, Associate Partner in the Energy & Utilities Practice and Global Business Services for IBM.

"The vast majority would recommend the Time-Of-Use pricing."

With help from IBM, the OEB launched the smart meter pilot project to enable consumers to learn the most cost-effective times to use energy.

The result was an overall reduction in electricity consumption. And about 90% of participants paid lower energy bills by being mindful of their time of use.

Almost 80% of participants said they would recommend Time-of-Use (TOU) pricing to their friends, because it made them more aware of how to reduce their bills and gave them greater control over their costs.

The report shows that TOU prices motivated the consumers who participated to shift some of their electricity use away from peak hours. The shift of consumption was largest for consumers who were on special pricing plans designed to shift usage on critical high demand days for power, such as very hot days in summer.

The pilot study was conducted with the support of Hydro Ottawa and was developed by two firms with extensive experience in TOU pricing pilots: IBM Canada and eMeter Strategic Consulting. Results show that the average reduction in electricity demand among the two-thirds of participants on critical pricing plans was more than 20% during high demand or critical peak hours in summer. Demand reduction on winter critical peak days was much lower for all participants.

The results also indicated that using smart meters with some form of TOU prices led to electricity conservation in most cases. Study participants reduced overall electricity consumption an average of 6% compared to a similar-sized group of Hydro Ottawa customers not paying TOU prices.

STUDY AND DESIGN OF POWER PLANT TRANSFORMER EXPLOSION AND FIRE PREVENTION - PART II

By David Scheurer, Research Department Engineer; Alexis Nesa, Research Department Engineer; Sylvain Prigent, Research Department Engineer; Philippe Magnier, C.E.O, SERGI; Moumèn Darcherif, Research Manager, EPMI

5.2 Analysis and consequences on transformer instrumentation and equipment

The electrical arc is a high temperature plasma. At this heat level, the oil cracking process generates sufficient gas to create the overpressure. Consequently, the pressure slopes are exponential, following the oil cracking process described in "Development of a Magneto-Hydrodynamic Model and Design of a Transformer, On Load Tap Changer and Bushing Oil Cable Box, Explosion and Fire Prevention". The vessel maximum tolerated pressure was determined to be 1.2 bars above atmospheric pressure.

Current	Pressure gradient at TRANSFORMER PROTECTOR operation		Pressure gradient at vessel explosion	
kA	bar per second	psi per second	bar per second	psi per second
35	60	855	100	1 400
118	130	1 900	200	2 900
236	930	13 500	2 300	33 000

Figure 7: Pressure gradient versus fault current

The pressure gradients versus current faults, reported in Figure 7, are of utmost importance, as they explain transformer explosion due to the inadequate in-service instrumentation or devices.

Regarding the transformer rapid pressure rise relay, mainly sold in the USA, since it only detects the pressure increase, a latency is expected before transformer tripping. In addition, it is designed to operate in the event of a short-circuit but its pressure rate limit is around 10 to 20 bar/second. In comparison with the values given above for every kind of insulation rupture, it can be noticed that rapid pressure rise relays are not adapted at all.

The results given in Figure 7 also explain the transformer pressure relief valve inefficiency, as all transformers are equipped with this device and explode anyway, even for very small short-circuits.

A comparison made by SERGI on pressure relief valves versus TRANSFORMER PROTECTOR for the above short-circuit conditions has proven that the vessel could not be saved for all incidents simulated.

Another topic concerns the generator circuit breakers. In light of the above results, doubts are increasing regarding their efficiency. The fault detection delay in addition to the breaker opening inertia apparently renders this costly protection inefficient for strong short-circuits.

6. ANALYSIS OF THE DEPRESSURIZATION CHAMBER RUPTURE DISK EFFICIENCY

A rupture disk is a device intended to prevent overpressures generally in chemical and petrochemical applications. Its goal is to protect systems from mechanical failures, chemical reactions and internal blasts. The disks are available in various materials, sizes, and configurations.

However, for the TRANSFORMER PROTECTOR, the main parameter to control was the opening time. In fact, to avoid vessel explosion for the worst cases, the SERGI rupture disk had to be fully opened in a matter of one millisecond.

This result was achieved after a large number of rupture disk tests, calculations and simulations, which were necessary to find the best design to avoid transformer explosion for severe short-circuits.

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The rupture disks manufactured for the TRANSFORMER PROTECTOR are made of stainless steel and dimensioned for different tarred pressures. For this study, a 0.8 bar set point depressurization pressure has been settled.

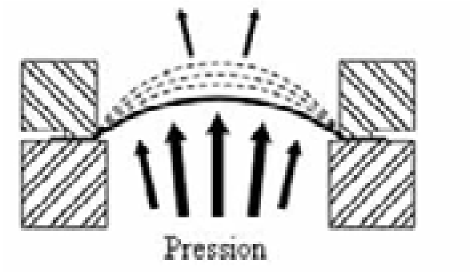

Figure 8: Rupture Disk opening principle

Rupture disks therefore split open at tarred pressure and release the excess of fluid, Figure 8.

The SERGI TRANSFORMER PROTECTOR depressurization chamber is generally located on the upper part of the transformer vessel.

Research regarding the opening time and behaviour of the rupture disk was conducted by SERGI. Its results were applied to the power plant transformer study.

The rupture disks complete opening time, versus diameters and fault levels are shown in Figure 9.

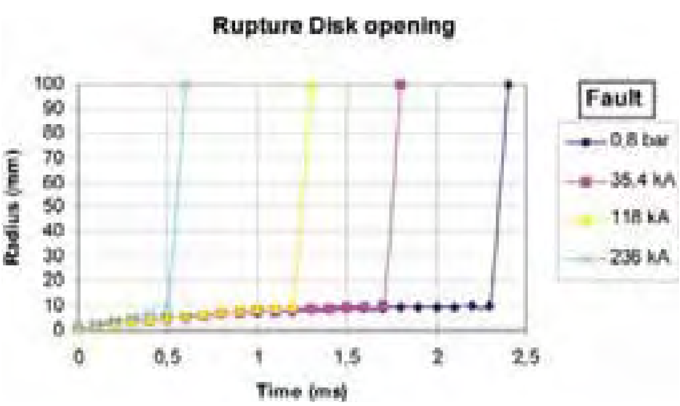

Figure 9: Rupture disk complete opening for different faults

The SERGI rupture disk complete opening time depends on the fault type, and varies from 0.6 millisecond for a very sharp pressure rise to 1.8 millisecond for a small short-circuit, as shown Figure 10:

Fault types	Rupture Disk opening time in ms
Manoeuvre shock of 35 kA	1.8
Lightning shock of 118 kA	1.2
Lightning shock of 236 kA	0.6

Figure 10: Rupture disk response versus fault type

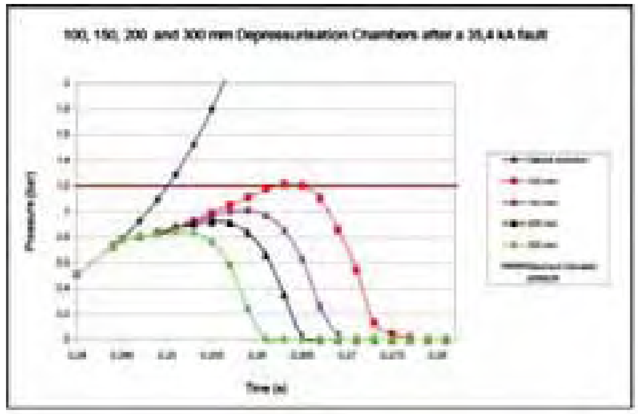

Figure 11: 34,5 kA short-circuit TRANSFORMER PROTECTOR response, pressure in bar and psi

Also, if the Rupture Disk is submitted to a 0.8 bar pressure step, the opening time depicted in Figure 9 is of 2.4 ms.

7. DEPRESSURIZATION CALCULATION

The SERGI TRANSFORMER PROTECTOR is based on the reactive opening of a rupture disk integrated in a depressurization chamber. In order to simulate the depressurization, 3 steps were followed:

• Different depressurization chamber diameters were created in the transformer tank in order to simulate the pressure evolution during short-circuit, versus size;

• The depressurization chamber conditions to the limits were modified (speed let free, suppression of heat exchange parameters on the opened area…);

• Exhaust speeds were calculated recursively, according to transformer pressure and depressurization chamber diameter.

The simulations were conducted for each short-circuit type and with different exhaust diameters Figure 11 to Figure 13.

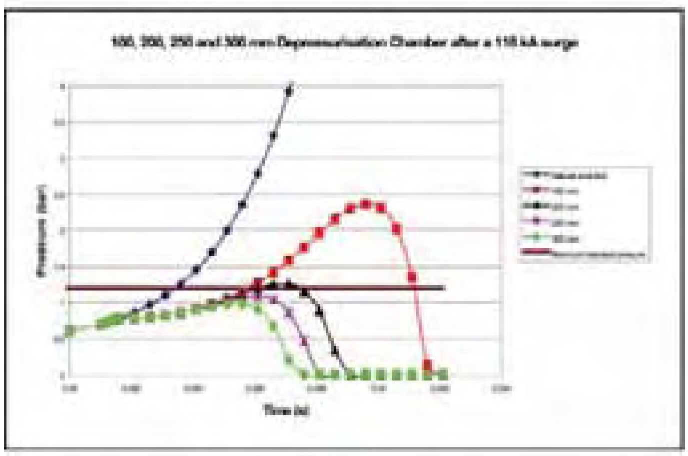

Figure 12: 118 kA short-circuit TRANSFORMER PROTECTOR response, pressure in bar and psi

The diameter of the rupture disk plays a significant role in the depressurization process. The tarred pressure is also of utmost importance, but in order to protect the Rupture Disk during maintenance period, it was decided to settle the

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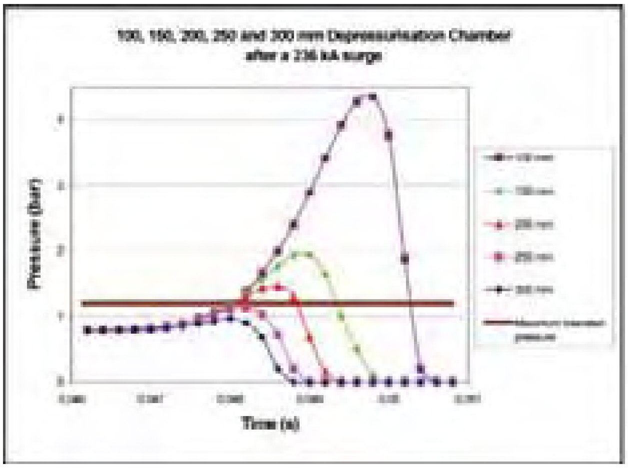

Figure 13: 236 kA short-circuit TRANSFORMER PROTECTOR response, pressure in bar and psi

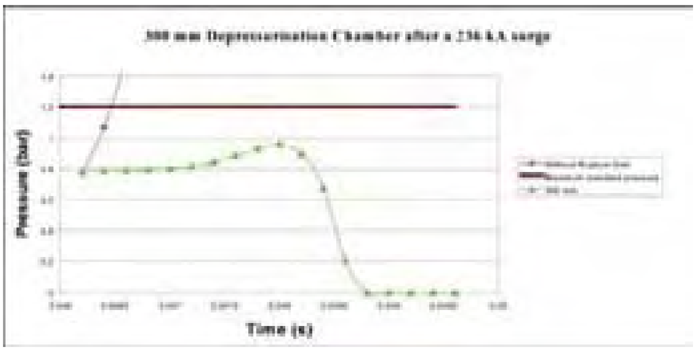

Figure 14: TRANSFORMER PROTECTOR efficiency for a severe lightning shock (236 kA), pressure in bar

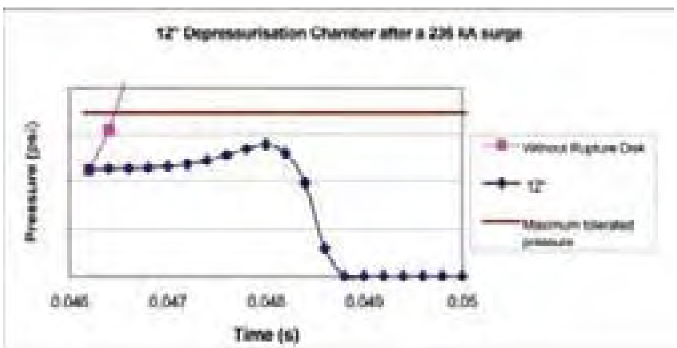

Figure 15: TRANSFORMER PROTECTOR efficiency for a severe lightning shock (236 kA), pressure in psi

bursting pressure at 0.8 bars (11.6 psi), above the relief valve, tarred at 0.55 bars (8 psi).

For the 236 kA short-circuit current, the most suitable depressurization chamber size is of 300 mm, 12 inches. The following Figures 14 and Figure 15 show a close-up of the TRANSFORMER PROTECTOR efficiency.

Time require for vessel depressurisation during short-circuit	
Current, kA	Time, millisecond
35	27
118	8
236	3,5

Figure 16: Time required for vessel depressurization during short-circuit

8. EVACUATED VOLUME CALCULATION

8.1 Preliminary

Before calculating the depressurized volume of oil, the scale of the time required for depressurization during short-circuit, shown in Figure 16, must be kept in mind.

The depressurization time starts at rupture disk opening and ends when the vessel pressure reaches the atmosphere level for the first time.

The depressurization for the 236kA fault is the quickest due to:

• The rupture disk fast opening time, as the pressure gradient is a key parameter to the opening time, according to section 6, “Analysis of the DEPRESSURIZATION CHAMBER Rupture Disk efficiency” and Figure 9: Rupture disk complete opening for different faults;

• The depressurization chamber diameter, which is in this case 300mm, 12 inches.

8.2 Calculation

The flow calculation was achieved with the following equation:

Q = S x V

With: Q flow in m3/s or en l/ms

S in m2

V in m/s

• The “S” section represents the equivalent fluid flow section of the different depressurization chambers. This depends on the size and opening equation of the rupture disk.

• The velocity “V” is based on the vessel internal pressure evolution.

With:

$$V = \sqrt{\frac{2\Delta P}{\rho}}$$

With: V in m/s

ΔP in Pasca

ρ in Kg/m^3

8.3 Results

The evacuated volume corresponds to the quantity expelled during depressurization, from the time corresponding to transformer internal pressure equal to P=0.8 bar to the moment when P=0 bar.

The values in Figure 17 tinted in grey are given for information only as the vessel has normally already exploded for the corresponding pressure values.

Continued on Page 54

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The calculated evacuated volume is larger for small and severe short-circuits. To explain this result, it is important to remember that:

• The pressure set point is the same for all calculations and therefore the gas quantity produced before pressure reaches 0.8 bars is the same for all examples.

• The only difference at the instant of opening is the pressure gradient.

• As explained in section 6, “Analysis of the DEPRESSURIZATION CHAMBER rupture disk efficiency”, the disk opening time varies according to the pressure slope.

• For the 236kA short-circuit current, the rupture disk opening time is 0.6 ms whereas it is 1.8 ms for the 35 kA fault.

• The opening speed is crucial to the depressurization process. The shortest opening time provokes the fastest pressure drop.

Hence, a quick depressurization provoked by a fast pressure rise, which gives a rapid rupture disk opening time will only require evacuating a small volume of oil.

	Short-circuit fault current					
	35kA		118kA		236kA	
Depressurisation Chamber diameter, mm	Evacuated oil and gas mixture average velocity, m/s	Evacuated oil and gas mixture volume, litre	Evacuated oil and gas mixture average velocity, m/s	Evacuated oil and gas mixture volume, litre	Evacuated oil and gas mixture average velocity, m/s	Evacuated oil and gas mixture volume, litre
300	0.824	13.18	0.914	5.48	X	2.14
250	X	X	0.674	4.38	0.705	1.97
200	0.369	8.118	0.448	3.36	X	1.42
150	0.218	5.66	X	X	0.269	1.02
100	0.098	3.33	0.134	1.407	0.147	0.67

Figure 17: Evacuated oil and gas volume versus Rupture Disk diameter

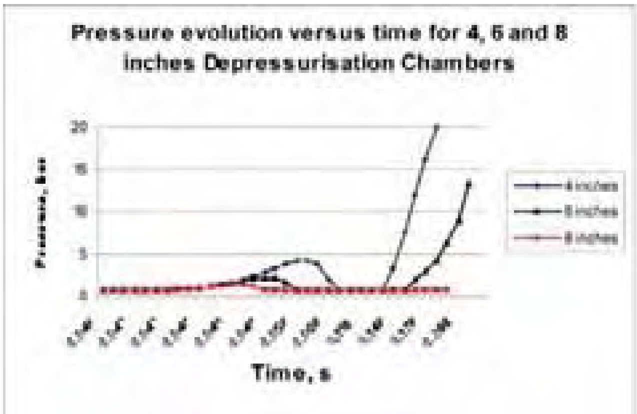

Figure 18: Depressurization chamber efficiency analysis for a 236kA short-circuit, pressure in bar and psi

9. DEPRESSURIZATION CHAMBER CALCULATION

The length of the depressurization chamber is designed according to the amount of oil to be expelled during the depressurization process, calculated in section 8.

However, an important fact that does not appear in section 8, “Evacuated Volume Calculation” and the figures presented in section 7, “Depressurization Calculation” is that when the rupture disk has operated, the generator is still feeding the fault in any case, and there might be a time lag before the circuit breaker opens the circuit on the grid side. These time lags imply that pressure is still building up, even though the rupture disk has operated.

Further calculations made for the worst 236kA short-circuit show that, with a 100mm, 4 inches, depressurization chamber, pressure drops normally but by keeping the transformer fed, the pressure quickly builds up again after approximately 200ms because of the exhaust inefficiency.

Greater indepth research for every efficient depressurization chamber diameters was therefore conducted to find the minimum diameter to prevent such an occurrence from happening. As a result, it was discovered that the minimum depressurization chamber diameter had to be equal to or greater than 200mm, 8 inches, to avoid another pressure build-up after the depressurization process, as shown Figure 18.

10. GENERATED GAS VOLUME CALCULATION

Gas production has played a major role in the transformer fire experienced by this western U.S. utility in one of their underground hydro plants. The total plant, 3 units, was put out of service for more than 4 months and the failed unit for more than 10 months, because of the gases generated by oil during the short circuit and resulting vessel explosion, but also by a "fireball" phenomenon due to indoor transformer location. When the walls inside a building are able to withstand an explosion, the explosive gases do not have immediate oxygen to burn instantaneously causing a "fireball" to travel, seeking oxygen. In this case, the "fireball" moved inside the power plant gallery to the 4 x 4 meter outer door, which was blown 60 meters away. The company requested SERGI to calculate the gas produced during the incident, in order to correctly size the TRANSFORMER PROTECTOR gas exhaust pipe that would be channeled outside the powerhouse.

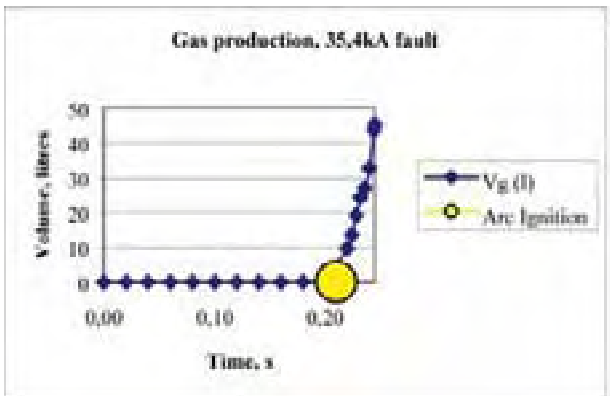

Figure 19 : Gas generation for the 35.4 kA fault

The MTH model and its associated software enable the calculation of the amount of gas generated during arcing.

Continued on Page 56

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However, the generated gas was calculated only during the fault prior to the rupture disk opening. As a matter of fact, after the system operation, the parameters, hypothesis and fluid routes are subjected to changes such that they are ruled as random and therefore barely quantifiable.

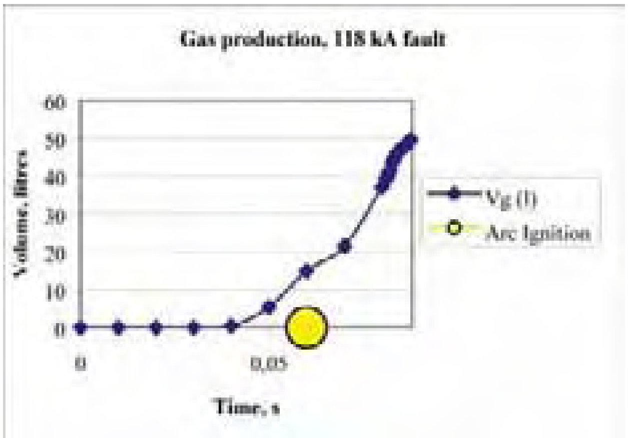

Figure 20: Gas generation for the 118 kA fault

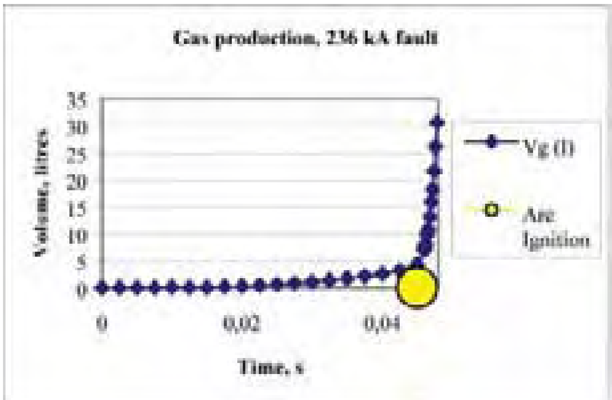

Figure 21: Gas generation for the 246 kA fault

Figures 19 to Figure 21 show the gas production graphics for each fault.

It can be noted that the generated gas volumes are of the same order, only the generation slopes change. Moreover, for all cases analyzed here, the TRANSFORMER PROTECTOR operates at 0.8 bar and the gas production is mainly proportional to the vessel pressure at the moment of system activation. However, except for the 35, 4kA case, a small amount of gas produced is noticed before arc ignition. It is uncertain whether this gas creation is due to the heating of the plasma channel prior to arcing, or to oil directly in contact with copper wire being decomposed.

After the TRANSFORMER PROTECTOR operation, the generator is feeding the fault in any case and another large quantity of gases is also produced, which explains the "fireball" strength observed during the hydropower plant transformer fire.

11. RECOMMENDED SOLUTIONS

11.1 Proposal to the utility

For this case, the SERGI recommended solution was based on the worst faults, for the lightning shock of 236kA experienced by the utility.

Every fault type was studied to properly size the explosion prevention system. The TRANSFORMER PROTECTOR is therefore specifically designed to protect every particular type of transformer and its associated oil-filled equipment.

In this particular case, the transformers are indoors, where explosion and resulting fire provoke very damaging incidents. The solution proposed by SERGI has therefore been designed to collect the gases after depressurization, to avoid contact with ambient air (oxygen), store the oil in a leak-tight tank always under nitrogen atmosphere, and evacuate the gases outside the building.

With this architecture, the TRANSFORMER PROTECTOR does not require or use the plant oil collecting routing and storage system.

The proposed installation is pictured in Figures 22 and 23 for a three-transformer bank. Moreover, the whole system can be adapted to 6 or 9 transformers, depending on the possibilities offered by the site arrangement.

The Oil Storage Tank, which is always under nitrogen atmosphere, is equipped with a 50 mm, 2 inches, pipe to evacuate the dangerous flammable gases to the outside and is installed per three units. However, each transformer must be equipped with a depressurization set, including maintenance valve, absorber, depressurization chamber and its associated rupture disk.

The solution provided by SERGI takes into account the transformer geometry and its location in the power station.

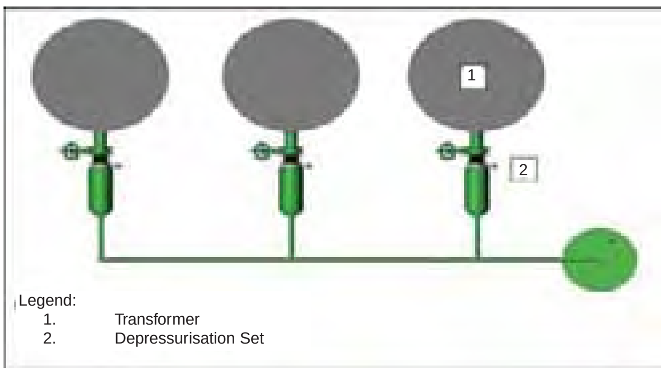

Figure 22: Top view of the proposed installation (out of scale)

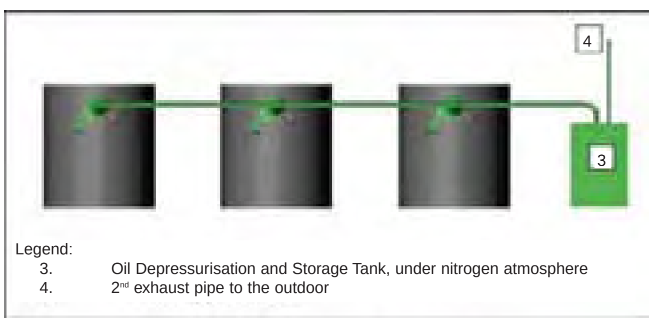

Figure 23: Side view of the proposed installation (out of scale)

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