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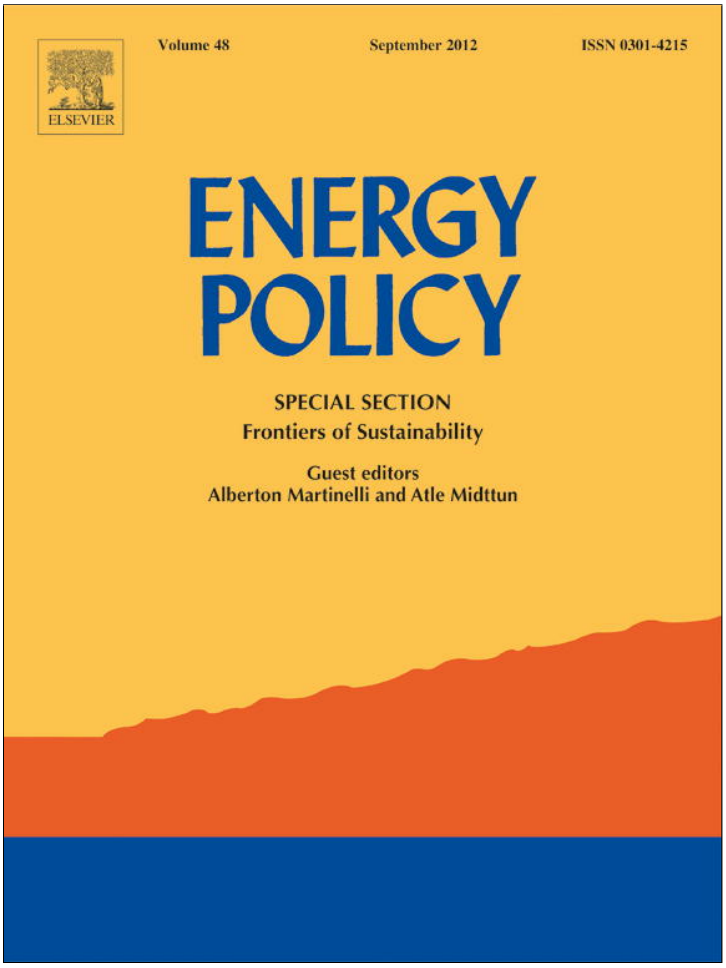

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The technical, economic and commercial viability of the vehicle-to-grid concept

Jonathan Mullan *, David Harries, Thomas Bräunl, Stephen Whitely

School of Electrical and Electronic Engineering, 35 Stirling Highway, University of Western Australia, Perth, Western Australia 6009, Australia

HIGHLIGHTS

- ▸ The Wholesale Electricity Market is used to evaluate variants of vehicle-to-grid.
- ▸ Arbitrage of the market is restricted to a few trading intervals each year.
- ▸ Implementing peak shaving through battery energy storage is cost prohibited.
- ▸ Supply of ancillary services is uncommercial when compared to conventional sources.
- ▸ Adding vehicle load to demand side management schemes is the most likely variant.

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ABSTRACT

The idea that electric vehicles can be used to supply power to the grid for stabilisation and peak time supply is compelling, especially in regions where traditional forms of storage, back up or peaking supply are unavailable or expensive. A number of variants of the vehicle-to-grid theme have been proposed and prototypes have proven that the technological means to deliver many of these are available. This study reviews the most popular variants and investigates their viability using Western Australia, the smallest wholesale electricity market in the world, as an extreme test case. Geographical and electrical isolation prevents the trade of energy and ancillary services with neighbouring regions and the flat landscape prohibits hydroelectric storage. Hot summers and the widespread use of air-conditioning means that peak energy demand is a growing issue, and the ongoing addition to already underutilised generation and transmission capacity is unsustainable. The report concludes that most variants of vehicle-to-grid currently require too much additional infrastructure investment, carry significant risk and are currently too costly to implement in the light of alternative options. Charging electric vehicles can, however, be added to planned demand side management schemes without the need for additional capital investment.

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1. Introduction

The issues associated with the use of internal combustion engines (ICEs) for vehicle transport have been many and persistent and interest in developing alternatives to both ICEs and transport fuels used in ICEs has existed ever since ICE vehicles first began to be used over 100 years ago. That interest has been greatly amplified over time by the rapid increase in numbers of vehicles and, in more recent decades, by the political, economic and environmental concerns over the risks created by the very high dependency of our transport systems on petroleum based fuels. Now, with most major vehicle manufacturers either planning or already starting to manufacture plug-in hybrid electric vehicles (PHEVs) and pure battery electric vehicles (BEVs), a steady transition to electric vehicles (EVs) over the coming decades appears to be in train. This electrification of the transport fleet over time will have major policy implications and some governments are already considering the issues (Queensland Government, 2010; EPRI, 2010).

One of the main policy issues associated with the electrification of the vehicle fleet is the potential impacts that recharging of EVs on a large scale will have on electricity grids (Sahili, 1973;

Abbreviations: AMI, advanced metering interface; BEV, battery electric vehicle; DoD, depth of discharge; DSM, demand side management; EV, electric vehicle; FRCC, Florida Reliability Coordinating Council; FRSG, Florida Reserve Sharing Group; HAN, Home Area Network; ICE, internal combustion engine; MCE, Ministerial Council on Energy; PHEV, plug-in hybrid electric vehicle; PV, photovoltaic; REV, Renewable Energy Vehicle; SOH, State of Health; SWIS, South West Interconnected System; V2G, vehicle-to-grid; WA, Western Australia; WEM, Wholesale Electricity Market (Western Australia)

* Corresponding author. Tel.: +61 421 122 985; fax: +61 8 9276 6795.
E-mail address: jmullan@optusnet.com.au (J. Mullan).

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Putrus et al., 2009; Savacool and Hirsh, 2009; Tao et al., 2009). Studies undertaken to date, however, have tended to conclude that, in the case of those electricity networks studied, the recharging of large numbers of EVs could be supported provided that the recharging is managed or controlled to avoid exacerbating peak loads (Harris, 2009; Mullan et al., 2011). It has also been suggested that the take-up of EVs is likely to be gradual due to the high costs of batteries and that this will provide electricity supply companies with ample time to foresee potential problems and to take action to mitigate any problems before they arise (Smith, 2009).

In parallel with this ongoing debate over the impacts that recharging of EVs will have on electricity demand has been a secondary discussion over whether EVs offer potential benefits for the management of electricity supply systems. These benefits can be separated into the enhanced control of demand for electricity, or Demand Side Management (DSM), and capacity that could be created by using EVs as distributed energy storage or generation units to supply electricity into the electricity grid when required, referred to as the vehicle-to-grid (V2G) concept. In an operating environment where energy storage capacity is both expensive and rare, and network upgrades to meet increasingly peaky demand are costly, V2G and vehicular DSM schemes have very strong appeal. This possibly explains why it is frequently assumed that these benefits will be automatically realised as the number of EVs penetrating the vehicle market increases. Few studies have been undertaken, however, to support this assumption (Dowds et al., 2010) and the purpose of this paper is to look more closely at the V2G concept in particular and the degree to which it is likely to be realised.

One of the difficulties in evaluating V2G and vehicular DSM concepts is that there are a number of variations on the theme. A number of types of V2G transactions are possible, and those commenting on the V2G concept frequently fail to distinguish between these. This paper therefore looks at the different types of V2G transactions and the technical and economic factors that will determine the viability of each of them. A case study based on a grid for which the application of the V2G would have particularly large benefits is then used to comment on the likelihood of each of the different types of V2G transactions being realised.

2. Basic assumptions of the V2G concept

We begin by making explicit the basic assumptions that underpin the V2G concept and the benefits that it is perceived to offer. The first assumption underlying the concept is that the batteries in electric vehicles are underutilised, that they could therefore be made available to form, in aggregate, a very large source of energy storage and that this could be used as a part of the electricity supply system. This assumption is relatively straightforward and is statistically uncontentious.

The second and related assumption is that most of the EVs will be idle for much of the time and will be parked in locations in which they could be readily connected to the grid. This assumption is also relatively uncontentious as statistics indicate that over 90% of current vehicles are usually parked at any given time (Brooks, 2002) including during peak hour traffic periods (Letendre and Kempton, 2002). This is important as peak hour traffic often coincides with peak electricity demand periods and, therefore, the time that it will be necessary for as many EVs as possible to be feeding into the grid (Kempton and Tomic, 2005a).

The third assumption is that the batteries in the EVs would represent a zero-cost energy storage system for the electricity supply industry as the batteries would have already been purchased for vehicle use. It is assumed that these batteries will be available for use by electricity supply companies as a source of energy storage capacity and that these companies will in this way have energy storage capacity available without the need to invest in this storage capacity.

The fourth assumption underpinning the V2G concept is that vehicle-to-grid transactions could be rendered highly predictable and reliable. For this to be possible, the numbers of participating EVs in a V2G scheme would need to be very large. Proponents of the V2G concept propose that this could be achieved by using an aggregator whose role would be to contract with electricity retailers or wholesale customers to sell large blocks of electricity into the regional power market, and to enter into back-to-back contracts with a large number of individual electric vehicle owners to purchase electricity supplied from their vehicles (Kempton and Tomic, 2005a). The aggregator would have no direct control over operating schedules of individual vehicles and would simply provide financial incentive to the vehicle owners to keep their vehicles plugged in whenever possible.

3. Perceived benefits of V2G

The benefits that EVs are perceived to potentially provide for the management of electricity supply systems can be separated into those on the demand side (demand side management benefits) and those on the supply side (V2G benefits). The latter are linked mainly to the benefits that are provided by incorporating energy storage into an energy supply system. One of these is the capacity to store excess electricity generated in times of low demand and the ability to use that stored energy during times of high demand. This is a well-established form of supply management used by the electricity supply industry wherever cost effective energy storage options are available. The lowest cost large scale energy storage option, and therefore by far the most common, is hydroelectric storage, which is often used in conjunction with base-load generating plant, such as nuclear or coal plant, to increase the overall utilisation and efficiency of the electricity supply system.

Another benefit that some forms of energy storage have is rapid response time. The output of hydroelectric storage schemes, for example, is varied by opening or closing valves and a hydroelectric plant can be brought on line within a matter of seconds compared to the minutes that it typically takes a gas-fired peaking generator to reach an acceptable level of efficiency. This rapid response time means that hydroelectric generation plant are able to efficiently provide ancillary services, such as frequency control, load following and spinning reserve at a relatively competitive cost.

Energy storage systems can also be used to enable the amount of intermittent renewable energy generation capacity connected to the grid to be increased. Once the amount of electricity supplied from generators with intermittent and unpredictable output exceeds a certain portion of an electricity supply system's total installed generation capacity, the fluctuating supply combined with the already fluctuating load becomes problematic for the stability of the electricity supply system. The threshold portion depends on the specific grid, but is usually between 10% and 30% of total installed capacity. In order to increase intermittent supply beyond these levels, network managers can either increase installed back-up generation capacity or install energy storage capacity. Back-up generation capacity is poorly utilised and therefore an expensive addition to the already high cost of renewable sources. In the same way that energy storage systems are used to absorb excess base-load power in times of low demand and release that at times of high demand, they can buffer supply intermittent renewable supply, increasing the amount

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of renewable energy generation that can be practically connected to the grid (Kempton and Tomic, 2005b; Hepworth, 2009; Levitan, 2010). This has significant policy implications as it would make the renewable energy targets set by governments more achievable.

Many see EVs as being able to provide some of the same benefits as traditional storage schemes (Gage, 2003; Brooks, 2002; Kempton and Tomic, 2005a). Within a fraction of a voltage cycle (at 50 Hz or 60 Hz), a 13 kW h EV battery pack can output over 50 kW of power for approximately 15 min. Bidirectional power flow and metering is already widely used for distributed generation systems, such as residential photovoltaic (PV) systems, and many of the major issues, such as voltage rise and islanding, are already well managed phenomena. Modern power supplies are highly controllable bidirectional power conversion devices capable of supplying power to the grid or demanding power from the grid at a specified level of power almost instantaneously. In addition, with filtering, these are capable of supplying a very clean sinusoidal current wave in steady state with less distortion than a typical supply generator unit. Electric vehicles, which already have a unidirectional AC–DC rectifier as a minimum, are therefore natural candidates to supply this service, if the charger is upgraded to one capable of bidirectional power flow.

The potential benefits of EVs for managing electricity supply systems therefore are seen by some to be very significant. The electrification of the vehicle fleet is in fact increasingly assumed to be a critical component of any strategy designed to accelerate the uptake of renewable energy. Wright and Hearps (2010), for example, maintain that 100% of Australia's energy could be supplied from renewable energy by 2020 if existing appliances, equipment and processes were replaced by highly efficient ones and if the take-up of EVs was sufficiently rapid.

The ability for much of those benefits to be realised, however, will require investment in complimentary technologies, commonly referred to as 'smart grid' technology, and here the debate encounters a second definitional problem as there are not one, but many definitions of a smart grid.

4. Smart grid requirements

A smart grid, or intelligent grid, is simply an existing grid into which current and emerging control, switching, communications and metering technologies are incorporated in order to enhance its functionality, flexibility, accessibility, reliability and efficiency and to reduce costs. Different technologies can be used to make a grid smarter in different ways. Remote meter reading, remote switching, remote fault reporting, utility-controlled demand management and increased capability to connect intermittent renewable energy and distributed generation are some of the more popular examples. Metering, however, is the critical component of any smart grid and is also of critical importance to the EV debate. Together with a vehicle's on-board control, it is metering functionality and communications requirements that will ultimately determine which of the V2G variants will be commercially practical.

5. Vehicle-to-grid transactions

V2G transactions involve the use of batteries in EVs to supply electricity into the grid when required. A fleet of EVs can supply significant and highly controllable levels of power to the grid in a very short space of time and a large enough pool of vehicles will provide a statistically reliable source of supply. The use of these batteries, however, comes at a cost.

Lithium ion batteries age through use and aging caused by V2G would need to be offset by the financial incentive paid to drivers taking part in a V2G scheme. Many aging models use total ampere-hour throughput to give an indication of the State of Health (SOH) of the battery (Marano et al., 2009). A shallow battery cycle causes less damage to a battery than does a deep cycle. However, a V2G scheme that requires many shallow charge discharge cycles may be more damaging than one that requires a single deep cycle per day.

The ability to deliver bulk supply and/or ancillary services is a compelling addition to the already lengthy list of benefits that EV technology brings. These two categories are broken down further.

5.1. *Ancillary services*

5.1.1. *Spinning reserve*

One way of quickly offsetting a sudden loss in supply caused, for example, by a generation fault is to rapidly bring alternate generating capacity on line. Spinning capacity is left idling at minimum power until required and might only be used on a handful of occasions per year. This essential capacity is by definition very poorly utilised and therefore very expensive on an energy basis. In deregulated electricity markets, the system operator offers suppliers incentives to provide the service by the grid operator through a capacity payment, as well as an energy payment while supplying power. In monopoly markets, the grid operator supplies this together with all forms of capacity and the price of doing so is absorbed as an unavoidable cost of doing business.

In much the same way, stored energy in idle vehicles could be used to quickly replace a loss of supply in the short term and EV technology has been demonstrated to have this capacity (Brooks, 2002). Unlike PV systems, which simply supply energy into the grid whenever the solar radiation levels are sufficiently high, supplying power from a vehicle to the grid is deliberate and controlled. This therefore requires some communication between the vehicle and the system manager, either directly or via a smart meter.

When taking energy from a vehicle, there must be an interface between the vehicle and the system manager so that power flow requirements can be passed on to the vehicle controller and the vehicle can accept or deny the request for power. The request could be denied, for example, if the battery level is too low or if it is anticipated that the vehicle owner could soon be using the vehicle.

The most simple grid request would be for the vehicle to supply either at full power level or not at all. Although a large supply in terms of household demand, when compared with the demand of the entire grid system, the amount of electricity supplied from a vehicle is a small incremental addition. There would therefore be little need to fine tune the level of power supplied by a vehicle, when the power supplied by V2G could be more easily managed by controlling the number of vehicles from which power is demanded at any point in time. This would simplify the communication message and interface between the system operator and the individual vehicle, however, in order to manage supply by requesting power from a specific number of vehicles, the communication network would need to be more sophisticated than a simple broadcast system. The grid could then either demand power or not and the vehicle could either accept or deny a demand for power, based upon battery state of charge and vehicle usage requirements. An interface between the driver and the vehicle would therefore have to be added to enable the driver to input some prediction when the vehicle would next be needed and together with how much power is likely to be required.

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Existing spinning reserve arrangements might take some tens of seconds to reach the demanded level. Network issues, such as millisecond propagation times, would therefore present few problems and the communications infrastructure between the grid and the vehicle would not have to be particularly sophisticated by modern day standards. The communications system would, however, have to be very secure and robust.

5.1.2. Load following

Load following is a fine tuning, or balancing, activity where supply is added to and removed from the grid in real time in order to match total supply with total demand. This is achieved by monitoring system frequency, which fluctuates depending upon whether supply is higher or lower than demand. The load following capacity is traditionally supplied by rapid start gas-fired plant or, where available, hydroelectric capacity that can rapidly vary the power supplied to the grid. Like spinning reserve, service providers are paid a capacity payment for load following services and also receive an energy payment when supplying power. Depending upon the management philosophy and the number of participating vehicles, this service could result in shallow or deep cycling of batteries.

Since load following is undertaken in real time, a communications system between the grid and the vehicle would have to be always-open, reliable and secure.

An issue with this type of system is that at start up, many power convertors' current signals tend to be fairly distorted until reaching a steady state. If EVs supplying the grid are simultaneously turned on and off regularly and on a significant scale, then this may cause significant power quality problems that would have to be addressed.

5.2. Bulk supply

5.2.1. EVs as distributed energy storage systems

Another variant of V2G is the use EVs to store excess electricity generated by renewable and non-renewable sources for release back into the grid when demand peaks. The goal is to smooth the daily demand curve by "valley filling" and "peak shaving". In this V2G scheme, vehicle batteries would be deep cycled on a daily basis.

Different EV configurations offer different energy storage capacity capabilities. First generation hybrid vehicles sold have relatively small batteries (1–2 kW h) and no electrical connection to the grid, making them impractical for V2G power. New plug-in hybrid electric vehicles (PHEVs) coming to market will have larger batteries and will be recharged by the grid. It has been argued that these larger batteries (6 kW h or more) will be large enough to provide V2G from the battery alone (Kempton and Tomic, 2005a). In fact, many are expecting PHEV batteries to be as high as 15 kW h (Marano et al., 2009) or 16 kW h (Miller, 2009).

With no alternative source of power, battery electric vehicles (BEVs) already have large batteries of 13 kW h or greater capacity. Even a modest adoption of Plug-in Electric Vehicles (PEVs) over the next few decades is therefore seen to represent a vast addition to the amount of electricity storage that will be connected to the electricity supply system (Hunwick, 2007). As this option involves deep cycling of vehicle batteries, it faces constraints.

Since BEVs have no alternate power supply it would be necessary to leave sufficient reserve energy to allow for unexpected journeys. PHEVs on the other hand have a petroleum supply that can be used in the instance of unexpected demand for the vehicle. The ability to program a vehicle's computer to hold back reserve supply to meet the needs of the driver and the vehicle introduces a cost, additional to that of a vehicle that was not going to participate in a V2G scheme. This also assumes that vehicle owners are able to plan their day to a reasonable level of accuracy and in the case of BEVs ignores to some extent the typically long recharge times. Again, as with all of the schemes discussed to far, the system would need to communicate with the vehicle in order to request power as outlined above.

In addition to that the system manager may need to plan capacity in order to establish how much of the peak can be "shaved". This would require some indication from the vehicle as to the amount of energy it has available and when the vehicle is next required. With that information, the system manager is able to know how much energy is available in aggregate across the participating fleet, for how long, and, in the case of BEVs, when the vehicle is likely to take energy back prior to its use. While some owners may want to use their vehicle ahead of the planned time, assuming vehicle owners are able to plan their usage to some degree of accuracy, this will not be the case of a significant portion of the connected fleet. It is therefore unlikely to greatly affect the overall supply of energy available to the grid. It would serve as a significant inconvenience to the vehicle owner if the battery has been excessively discharged.

Finally, lithium ion batteries are damaged if discharged completely. Therefore for all PEVs participating, some energy would need to be retained in the pack in order to prevent premature aging.

5.2.2. EVs as distributed generators

In addition to providing energy storage, it has been proposed that the internal combustion engines of a plug-in hybrid vehicle could also be used to generate electricity for supply to the grid (Kempton and Tomic, 2005a, 2005b; Hunwick, 2007), in the same way that the energy generated by a residential solar PV panel is fed into the grid using an inverter (DC–AC). Hybrid vehicles operating in the motor-generator mode fuelled by petrol or a natural gas line have a power capacity up to 30 kW. A parked prototype vehicle used to generate AC power supplied into either the grid or a stand-alone load has been demonstrated (Gage, 2003). In that particular circumstance, interactions between the vehicle and the grid, including power flow, were controlled from remote locations via a wireless internet connection.

Kempton and Tomic (2005b) argue that optimum dispatch using a PHEV combustion engine would be to run the vehicle engine at maximum power as this maximises efficiency and minimises wear per unit electricity produced. Kempton et al. (2001) note that the power and energy supplied depends on the charger capacity, infrastructure capacity, fuel or electricity needed for the next trip, whether a continuous piped gaseous fuel source is connected to the vehicle, and a number of other factors.

Many vehicles will have AC motors and will therefore already have a high quality inverter within the motor controller module. A PHEV used as a distributed source of electricity, however, would require a comprehensive grid interface to include features such as the ability to remotely start and stop the internal combustion engine as required, and perhaps even more complex functions for example disengaging the engine from the drive shaft prior to running if parked in gear.

There are also a number of safety issues associated with the remote and automated start of a vehicle engine and running engines at near full load. Running an unsupervised vehicle at near full load poses a number of risks to the vehicle, the building in which it is housed and people in the vicinity. In the instance of mechanical failure or poor maintenance causing, for example, reduced radiator coolant or low engine oil, an overheated engine run remotely at full load would eventually suffer catastrophic

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failure with potentially lethal result. In addition, running a vehicle in the confines of a garage at home in the middle of the night poses a serious hazard if lethal exhaust fumes were able to drift through the home and a high revving engine would possibly cause some disturbance to local residents. Kempton and Tomic (2005b) acknowledge that there are safety and convenience issues that need to be considered.

In addition, being able to start a vehicle via an external interface may pose a security weakness. For this to be a practical option, various fail-safe safety systems would therefore have to be in place. As with demand side management, any communications networks would need to have a highly robust topology, with no single points of failure and a state of the art security system.

Finally, the idea of using internal combustion engines to automatically generate electricity runs counter to some of the key drivers for electric vehicles such as reducing the dependency on oil and tailpipe pollution. The idea imposes that future supply strategies of the stationary energy sector include a dependence on oil, where there currently is none, by implementing a technology designed to reduce the use of oil in the transport sector. Additionally, it is highly unlikely that electricity could be generated by vehicles as efficiently, at as low a cost, and with lower emissions than large-scale purpose-built generation plant.

5.3. Demand side management (DSM)

Demand side management, also called load shedding, is usually considered as an ancillary service, but is treated separately here because power flows in one direction only, from the grid to the load. DSM is used to stabilise the grid by balancing demand with supply. Until the emergence of smart metering, this service has been conventionally supplied by very large industrial users via interruptible load contracts. These users are paid a demand capacity payment for agreeing to allow their loads to be reduced or completely shut off during critical peak periods. This helps grid managers to bring demand and supply back into balance quickly during major supply failures while alternate generation capacity is brought on line.

In that respect, DSM has the same function as spinning reserve. The capacity to significantly reduce demand to achieve the same outcome has lead to DSM being treated by network managers as a form of "virtual supply". The concept has been popularised over the last three decades and the term "negawatts" coined, due to a typographical error, as the virtual energy supply units (Lovins, 1989).

Industrial customers might be able reduce operations for one or two instances per year, but any more would be impractical and so the service is seldom used to reduce peak demand levels. At the residential level some loads can be interrupted without causing inconvenience to the household. These can be simply managed by network operators and switched off via the smart meter. Loads such as air conditioner condensers represent some of the largest residential loads and are a major contributing factor to peak demand. Turning those off for short periods has relatively little effect on the overall function of the appliance. For example, if it takes 20 min on a hot day for the temperature in a house rise noticeably after the air conditioner has been turned off, then switching off the condenser for a period of 20 min in every hour in order to reduce peak demand would cause some inconvenience to the inhabitants. If however, the condenser was switched off for 10 min in every 30 min, or 5 min in every 15 min, then the residents would probably be unaware, while peak time residential air conditioner load is reduced by one-third.

It can also be used to improve power quality on the distribution network by reducing feeder demand at the local level in order to prevent overload and to clear faults more quickly. Reinstating a feeder is notoriously difficult. In cold start situations, which occur when feeders are brought back on line after a lengthy outage, temperature-sensitive loads, such as refrigerators, air conditioners and heating, turn on simultaneously as power is restored, resulting in an overload and causing protection devices to trip or fuses to blow.

For these reasons, the demand side management focus is shifting to the residential and commercial sectors with trials being run by power utilities in North America, Europe, Asia and Australia. Of course, in order to manage a particular load, it must be drawing power at the time. One criticism of the use of residential and commercial loads is that, unlike industrial loads, they are not always in use and so the ability to use residential and commercial loads to completely replace spinning reserve or industrial DSM is presently unrealistic.

The greater the number of loads, and the more diverse those loads are, the more reliable and robust a demand side management scheme is for any given level of demand. A charging vehicle that might have all nights, or the entire working day to replenish its battery could also be interrupted with little impact on the owner. As charging an electric vehicle can represent anything from a 1.5 kW to a 10 kW source of demand, depending upon the available infrastructure, the charger and the battery technology. So, even a relatively small number of vehicles would represent a significant aggregate demand. This would significantly increase the number of residential demand side management opportunities. The ability to rapidly turn off large numbers of diverse residential appliances could represent a major and robust source of demand reduction that could be used as an alternate to industrial sources if there is a loss of supply.

In many parts of the world, "dumb" meters are being replaced by smart meters where cost benefit analysis has found a positive return on investment from being able to read meters and switch supply on and off remotely. Smart meters will therefore already communicate in some way with system management in order achieve core functionality. In Australia, on the basis of air conditioning trials, the addition of demand side management functionality as part of the minimum national smart meter standard has been recommended by utilities (National Electricity Regulatory Authority, 2007).

The quality of the communications network required to support DSM would be similar to that already being implemented for smart grids. Under normal circumstances, the meter might need to make contact with the controlling system only when the status changes, i.e. when the load is switched on or off, indicating whether it is available for load shedding if required. In the instance that there is a need, the system could then send out a message to switch off the appropriate number of loads and reduce demand as required.

6. Case study—South West Interconnected System (SWIS) of Western Australia

6.1. Introduction

In order to evaluate the vehicle-to-grid schemes and the likelihood that electricity network operators and consumers will participate, it is useful to use an extreme case study where these schemes would be of particular benefit. One such example is the primary electricity network in Western Australia, or the South West Interconnected System (SWIS). The Western Australian Wholesale Electricity Market (WEM) has the distinction of being the smallest wholesale electricity market in the world. The size and isolation of the SWIS make the economic and operating conditions in the WEM one of the most extreme electricity markets. The area supplied by the SWIS is geographically and

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electrically isolated from the rest of the Australia. On the whole, vehicles purchased in Western Australia stay in Western Australia, and electrical demand in Western Australia is met by power generated in Western Australia. As a test case, then, the area supplied by the SWIS can be considered a microcosm from which generalisations can be made of much larger systems elsewhere.

The SWIS comprises more than 96,000 km of powerlines and almost 14,000 substations, covers an area of 322,000 km, and supplies the electricity demand of a population of 1.5 million (Western Power, 2010a). In terms of area, the SWIS is approximately 18% of the size of the largest regional network in North America, the Western Interconnection, which supplies power to the west coasts of the United States and Canada, and Baja California in Mexico (Western Electricty Coordinating Council, 2011). In terms of customer base, however, the SWIS supplies only 2% of the population supplied by the Western Interconnection (Western Electricty Coordinating Council, 2011). The population density is therefore an order of magnitude lower in the area covered by the SWIS to that covered by the Western Interconnection, making the cost of infrastructure per person in the SWIS high in comparison. Distributed sources of electrical generation or storage would therefore bring significant economic benefits in reducing the need to increase network capacity.

The SWIS is also characterised by 'peaky' loads that are caused by a high penetration of air conditioners and other appliances and equipment for which levels of use are closely related to ambient temperature. Summer peak time demand reaches 3800 MW, while minimum demand is approximately 1500 MW (Western Power, 2010b). Maximum temperatures can reach over 40 °C (104 F), the highest temperature recorded in the capital city, Perth, being 46.2 °C (115.2 F). While these very high temperatures typically occur for only a few days in a year, capacity planning is dominated by temperature. The flat Western Australian landscape prevents the adoption of hydroelectric plant and the system therefore lacks any storage capacity. Together with isolation, this means that capacity planning requires installed capacity to meet the one year in every 10 extreme temperatures in order to avoid the possibility of blackout. The result is low utilisation of much of the generation and network infrastructure. Distributed energy storage used to supply power during the peak and storing power during off-peak times, together with demand side management would bring about major economic benefits in improving utilisation by curtailing the growth in peak demand and redistributing demand to off-peak times.

The generation system comprises a small number of coal-fired generators, which are used to meet base and shoulder loads, and an equally small number of gas and diesel-fired generation plant that are used predominately to meet peak loads. In terms of installed generation capacity, the SWIS is a relatively small grid and is more appropriately compared in size with some of the 11 component balancing authorities making up the United States' smallest regional network, the Florida Reliability Coordinating Council. These are shown in Table 1.

Even in large electricity networks supply side events, such as unexpected loss of generation, can have a significant effect on grid stability and reserve capacity must be on hand to replace lost supply. The capacity of the largest generator connected to the grid in Western Australia is only 340 MW, representing almost 9% of total annual peak demand. In the examples shown in Table 1, the largest generation unit can represent up to 20% of peak demand. Therefore those would be significantly more exposed to plant failure if standing alone. In the United States, BAL-002-1 Disturbance Control Standard requires each Balancing Authority to maintain a Contingency Reserve made up of reserve capacity and interruptible supply in order to cover sudden loss of plant. The level of reserve held by a Balancing Authority must be capable of covering the most severe single contingency. That may be loss of the largest generation unit or a particular network component that would result in the largest single loss of supply. Of the Contingency Reserve, the standard requires that half must be spinning.

In making use of the network interconnections and the negligible risk of simultaneously suffering the most severe loss of capacity, the balancing authorities can share contingency reserve obligations, and BAL-002-1 makes provision for Reserve Sharing Groups. The Florida Reserve Sharing Group (FRSG), which is made up of the 11 balancing authorities making up the Florida Regional Council, has a combined summertime peak of approximately 47,700 MW (Florida Reliability Coordinating Council Inc., 2009), making this region more than 13 times larger, in terms of demand, than the SWIS in Western Australia. If operating individually, in 2009, the members of the FRSG would need to find a combined Contingency Reserve of approximately 4600 MW, of which BAL-002-1 requires 2300 MW must be spinning. Operating as a group, however, the FRSG reduced the total Contingency Reserve requirement in that year to approximately 910 MW, of which 455 MW must be spinning.

In contrast, the WEM market rules require that enough spinning reserve must be available to cover the loss of 70% of the largest generator, or 238 MW. Table 2 shows how the three Florida balancing authorities considered above benefit from interconnection and participation in reserve sharing.

The SWIS is therefore highly exposed to plant failure and as a consequence there is a disproportionately high reliance on spinning reserve when compared to interconnected networks with access to a wider range of contingency reserve and reserve sharing options.

This small size of the system and its vulnerability to instability also places significant constraints on the ability to connect renewable energy generation that has unpredictable and intermittent output, such as wind turbines and solar PV systems. As wind represents the lowest cost renewable energy generation option and residential solar PV represents the most popular distributed renewable energy generation option, this makes any renewable energy targets difficult to achieve despite Western Australia's excellent wind and solar resources. The lack of hydroelectric storage means that there are no traditional options available to buffer demand and supply imbalances.

These factors render the V2G concept highly attractive to those managing the Western Australian electricity supply system and this makes the SWIS an excellent test bed for assessing the viability of the concept. If V2G technology proves to be feasible,

Table 1
Comparable balancing authorities operating in the Florida Reliability Coordinating Council Inc., 2009.

Balancing Authority	Adjusted peak demand (MW)	Largest generation unit/adjusted capacity
Tampa Electric Company	4428	Big Bend—450 MW
Seminole Electric Cooperative	3269	Seminole—693 MW
Florida Municipal Power Pool	3333	Stanton A—637 MW

Table 2
Spinning reserve requirements under varying market conditions.

Balancing Authority	WEM market rules (MW)	Isolated (BAL-002) (MW)	Participating in FRSG (MW)
Tampa Electric Company	315	225	47.2
Seminole Electric Cooperative	485	347	49.6
Florida Municipal Power Pool	446	319	86.4

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then it is likely to offer greater benefits and to potentially have a disproportionately larger role to play in helping to manage a network such as the SWIS than it would on larger and more stable interconnected networks, or networks that already have significant storage capability. New opportunities such as V2G must be viable in the WEM if they are to be successfully implemented in less challenging markets

Finally, the SWIS is a useful test case because, unlike markets elsewhere, generation has been separated from network management and balancing. This means that ancillary services are supplied via "arms length" transactions and the market price of these services is now well established and publicly available.

6.2. Smart grid

The type of 'smart' meters to be rolled out in Western Australia, and the functionality that they will have, is currently being considered by policy makers and the industry in all Australian states through the Ministerial Council on Energy (MCE), a high level national policy making body made up of all state and federal ministers for energy. The driver for policy making process has been the need to establish a national standard of smart meter functionality in order to minimise the cost of a national smart meter rollout. The standard adopted by the MCE is expected to set the level of smart meter functionality throughout Australia.

Many utilities and some states have already started to roll out smart meters. In Western Australia, for example, it is already possible for customers to pay to have a smart meter installed so that they can switch to a time-of-use or "smart tariff" that the retailer offers to customers to encourage a shift in demand away from peak periods. Residential customers that install solar PV systems are also required to install 'smart meters' with the ability to monitor and record two-way energy flows into and out of a customer's premise on a half hourly basis so that electricity injected into the distribution network from distributed generation can be accurately metered (National Electricity Regulatory Authority, 2007). The network operator in Western Australia, Western Power, is undertaking a initial roll out of smart meters through the Perth Solar City project as an initial broad scale role out trial (Western Power, 2010b) and the publicly owned retailer, Synergy, is rolling out a trial of 500 home smart meter trial in order to undertake its own evaluation of the costs and benefits of a smart meter roll out.

All of these initiatives have used meters that support time-of-use tariff metering and therefore conform to the minimum smart meter functionality recommended by the MCE. At this stage it therefore appears likely that the MCE's recommended minimum functionality smart meter will be adopted as the standard in Western Australia and elsewhere in Australia. While that minimum standard supports demand side management, it does not directly support V2G transactions and therefore does not include a communications interface directly between the meter and the vehicle. Additional investment would be required in order that V2G transactions could be undertaken. The meter, however, includes an advanced metering interface (AMI) for the Home Area Network (HAN) and an electric vehicle could be connected via a supporting HAN system (Department of Primary Industries, 2008; PECO, 2009).

6.3. Timeframe

Near-term use of electric vehicles to replace generation or to reduce investment in transmission network augmentation is highly unlikely as it will take time for vehicle numbers to reach the critical mass required to make V2G statistically reliable. It will take even longer before the technology is sufficiently proven for industry planners to start to include V2G in their planning. Furthermore, as the feasibility planning to the commissioning stages of new power generation plant can take up to 10 years, new conventional generation plant used to supply electricity and provide ancillary services are likely to appear in the generation mix for at least 10 years after V2G technology is proven, further slowing the adoption of V2G schemes.

6.4. Economic issues

6.4.1. Competing options

Owners of existing plant that supply base-load and ancillary services have made a capital investment in capacity with an expected economic return on investment. Using electric vehicles to replace that installed base load and ancillary services capacity would prevent those investors from receiving forecasted returns which would introduce significant uncertainty in future investment in generation capacity. It therefore would be unlikely that any government or system regulator would find in favour of such action.

For owners of EVs to use their vehicle batteries to enter these markets then, they would have to compete with new capacity, installed to meet new demand or replace retired plant. EVs therefore would have to represent a clear economic benefit over competing options.

6.4.2. The capital cost of smart grids

V2G options might increase the long-term benefits of the planned rollout of a smart grid in Australia, but the cost benefit analysis undertaken as a part of that process has not included an assessment of the V2G option. Most of the MCE's justification for smart meters came from the cost savings brought about by remote meter reading and through the use of time of day and critical peak pricing to promote the use of off-peak power usage. The following analysis therefore assumes that smart meters, as recommended by the MCE, will be available and funded by the many other benefits obtained.

The MCE smart meter standard functionality includes demand side management and communication between the system management and the meter over a number of communication standards. Any vehicle-to-grid application that requires a meter capable of communicating with the vehicle would not be included in the current smart meter rollout plans. V2G functionalities will not be available without additional investment on the part of the vehicle owner in appropriate HAN technologies and the network operator in supporting the particular type of V2G transaction. The cost of upgrading a smart grid with this functionality would therefore have to be factored into a V2G cost benefit analysis.

The Network Access Code, which governs the way that the network operator in Western Australia, Western Power, extends and interfaces its network with the end customer, requires all Western Power's investments to be economic. This has been increasingly emphasised with the Economic Regulator rejecting much of Western Powers application for funding on smart grid technologies. The cost of any new infrastructure will therefore need to be fully recoverable, either by tariff revenue from customers, cost savings or by charging a capital contributions fee. There must therefore be a recoverable economic benefit for a rollout of such infrastructure with functionalities beyond those that will be in place. Since these systems have not been rolled out on any more than an experimental scale, it is difficult at this stage to accurately estimate the cost of the different components of a system capable of supporting the different V2G variants.

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Standardisation issues also arise that will have to be adopted by vehicle manufacturers, HAN manufacturers and network management developers alike. A standardised data set of information passing between vehicle, HAN and the grid, presented in a standardised format, would be required for interoperability between different vendor systems.

Since few plug-in electric vehicles have been sold, there is no way of knowing whether the necessary hardware and software required to communicate with the grid and to deliver AC power to the grid will be standard equipment, what the cost premium would be, or whether it would be available at all when vehicles are eventually manufactured on a significant scale.

It is known, however, that a rollout of smart meters and the adoption of a smart grid that meets the specific requirements of a particular V2G application would require a major capital investment. While smart meters capable of demand management look to be rolled out across Western Australia, this is not the case for applications requiring communication between the vehicle and the meter.

6.4.3. The capital cost of a communications network

The fact that EVs are a distributed and moving source brings about a number of key issues. Using EVs for a type of V2G or G2V transaction would require investment in a widespread communications system with many times more access points than there are participating vehicles. This would be very expensive to implement. In the case of real-time applications, such as load following, this network would have to be always open, which would further add to the cost of implementation. In addition, with so many access points, the network would be vulnerable to cyber attack. When competing against the existing arrangements of a few stationary providers where a small and secure private network can be used, any communications requirements additional to what will be put in place to meet smart metering core functions could be prohibitive for load following.

6.4.4. Risk of limited participation

In the case of a battery electric vehicle, participation of a vehicle owner in a V2G scheme introduces a risk, or at least a perceived risk, that the batteries may not have sufficient power to enable the vehicle to be used if unexpectedly required. This risk, whether real or not, may reduce willingness to participate. Vehicle owners may decide to not participate at all or to limit their participation to only those times that they are absolutely certain that they will not need their vehicles.

As far as managing the electricity supply is concerned, participation that is restricted to set times of day or days of the week would potentially make the scheme unworkable. If vehicle owners participate only at night, then traditional generation capacity will still have to be available during the day, paid for under the reserve capacity mechanism and ancillary services supply contracts. The justification of a V2G scheme is that it would avoid the need for this investment in the expansion of conventional infrastructure or competing technologies. A V2G service that is unavailable at any point in time would be seen as being insufficiently reliable to avoid this investment.

Furthermore, since demand is very low at night there will always be traditional generation and transmission capacity available. This will impact on the return on investment and may contribute to making the concept unfeasible.

There would be a significant fixed cost component to any capital investment in a V2G scheme in upgrading the smart grid capabilities, such as the purchase and implementation of the centralised management hardware, software and networking equipment. Based upon the tight economic constraints under which Western Power currently operates, there must be a clear economic benefit to make the necessary capital investment. If the number of participating vehicles was limited, then there would be a real risk to Western Power that the investment would not return in the forecasted economic benefits. This poses a major constraint. The infrastructure must be in place in order for participation to occur, yet participation is not guaranteed. While smart meters can be redeployed, in contrast, the central management systems cannot.

From the vehicle owner's perspective, there must also be a clear economic benefit for providing V2G capacity. This would require recovery of all associated costs, together with sufficient profit to persuade the vehicle owner to participate on a regular basis. The economics for vehicle owners would be greatly affected by the cost of both the installation of any additional infrastructure and the wear and tear on vehicle batteries.

6.4.5. Battery wear

Battery wear is a function of energy (ampere hour) throughput, depth of discharge and overheating by high-current discharging or charging for long periods and/or in hot conditions. These factors favour the partial dispatch of a large number of batteries, rather than full discharge of a few batteries (Kempton and Tomic, 2005a).

Electrically, batteries are highly non-linear and many of the factors that affect battery performance are in themselves non-linear. Capacity depends greatly upon the conditions to which the battery is, and has been, subjected both during use, together with battery age. Nonetheless, the capacity of a 90 A h unit can be estimated as follows:

$$90\text{A h} \times 3.2\text{V} = 288\text{W h} = 0.288\text{kW h} \quad (1)$$

Measurements taken by the University of Western Australia's Renewable Energy Vehicle project confirm that this estimate is reasonably accurate for a new battery pack, having shown that a new pack of forty-five 90 A h Thundersky batteries hold approximately 13 kW h of electricity. At the time of writing, a single 90 A h battery costs approximately AUD160 delivered in Australia. While cheaper sources are available online, prices quoted do not include shipping costs.

According to one lithium ion battery manufacturer (Thunder Sky Energy Group Ltd., 2007), a lithium ion battery has a life of 3000 charge cycles at an average depth of discharge (DoD) of 80% and 5000 at an average DoD of 70%.

A simple calculation based upon these numbers (Table 3) shows that a vehicle owner would need to be paid 25 c/kW h or 17 c/kW h for discharges of 80% and 70% of nominal capacity, respectively, to be compensated for battery wear alone.

The current residential retail electricity tariff in Western Australia is 20.42 c/kW h. Without taking into account the initial purchase of the energy a vehicle owner would have to be paid approximately the residential retail rate just to cover depreciation. This may well underestimate the actual price the owner would need to be paid to cover costs as it assumes no other capital expenditure is made by the vehicle owner, i.e. the vehicle

Table 3
Depreciation costs of electricity supplied from Li-ion batteries.

Item	Battery Life	
	3000 (80% DOD)	5000 (70% DOD)
Power per cycle per battery (kW h)	0.2311	0.2022
Less inverter losses (7%)	0.2149	0.1881
Cost per cycle per battery (AUD)	0.0533	0.0320
Depreciation cost per unit of power (AUD/kW h)	0.25	0.17

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is already equipped with the necessary power electronics to invert the DC battery supply to a clean AC current conforming to local safety standards at no extra cost, any additional Home Area Network infrastructure is already installed, and that the network operator pays for all of the smart metering and communications costs.

In order for a V2G scheme to work, there would need to be sufficient opportunity to arbitrage the market, that is buy low during off-peak times and sell at a profit during peak times. At the retail level, the calculations above show that this type of scheme makes little sense. Short term price fluctuations do occur, however, in the wholesale market.

6.4.6. Supply of power—bulk supply

In the National Electricity Market (NEM) that operates in the eastern states of Australia, the electricity market spot price is able to fluctuate significantly depending on demand and supply. Research into V2G opportunities tends to assume a volatile, demand dependent spot price. In Western Australia, however, consumers are shielded from such price volatility in return for de-risking capital investment in generation capacity. Owners of generation plant are paid a capacity payment, whether used or not, plus an energy payment for any energy generated. The vast proportion of energy is purchased under contractual arrangement and only a small portion is traded on a daily basis under the Short Term Energy Market (STEM), a clearing system. Furthermore, the market rules require that prices offered in the STEM bidding process are based upon cost of supply rather than on the level of demand. Prices do rise during peak demand times, but only because expensive peaking power generation units are used. Therefore, the short-term prices in Western Australia are far less volatile than many other parts of the world. This arrangement is the key in attracting investment to this very small, "peaky" market.

Over 2009 and 2010, there were 35,040 half hourly trading intervals. In that period prices peaked at 33.6 c/kW h (Fig. 1). Analysis of all half hourly trading intervals over the two-year period between August 2007 and August 2009 shows that STEM prices rarely rise above the retail off-peak price of 10.78 c/kW h (Independent Market Operator, 2010).

This means that there would have been very few opportunities for a vehicle owner to arbitrage the electricity market in that time by buying during the off-peak times and selling during the peak times. Since there is only one peak per day, the assumption is that a vehicle could sell energy to the market only once per day and in fact it was found that over the entire two-year period, the vehicle owner would cover his or her costs on only five occasions (Table 4).

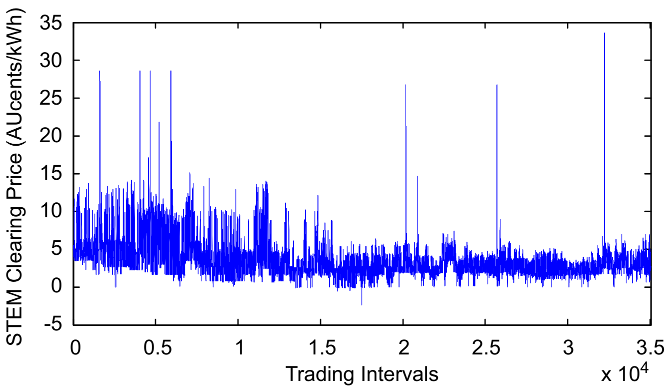

Fig. 1. Short Term Energy Market 2009–2010 (adapted from (Independent Market Operator, 2010)).

Table 4
Number of days that STEM prices exceed estimated costs (Independent Market Operator, 2010).

Pure battery depreciation cost	10
Battery depreciation plus off-peak energy (10.78 c/kW h) cost	5

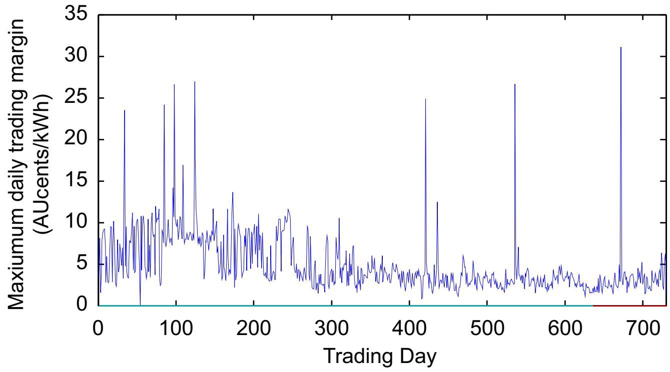

Fig. 2. Maximum possible daily trading margin on the Western Australian Short Term Electricity Market (STEM) 2009–2010 (Independent Market Operator, 2010).

Since STEM prices are lower than the off-peak retail price, future reduction in battery prices would do little to ease the situation and, based on the above, and a viable V2G scheme would need to allow the vehicle owner to purchase energy at a wholesale rate. Fig. 2 shows the maximum possible daily margin, that is difference between the daily maximum and daily minimum STEM pricing, that can be obtain by arbitraging the STEM through the use of energy storage.

Assuming vehicle owners are able to attain the maximum possible margin each day by buying at the daily minimum price and selling at the daily maximum price, if that margin is greater than the battery depreciation cost, then costs are covered and participation in a V2G scheme would result in a financial benefit. Inspection of Fig. 2 shows, however, that there were only 8 day over the two-year period on which the margin between the maximum and minimum STEM prices exceeded battery depreciation costs, bringing a total benefit to the vehicle owner of AU$5.49. Assuming a 50% fall in battery price from the current AU$160 to AU$80, the number of arbitrage opportunities increases to 102 over the two-year period. However, many of those are marginal and the after-costs return to the vehicle owner rises to only AU$23.01.

In addition to revenues from energy sales, generators supplying power to the SWIS are paid a capacity payment of AU$144,000 per MW available, through the reserve capacity mechanism (RCM). The requirement that capacity is available at all times is statistically realistic across a large pool of participants. A 13 kW h battery could then attract approximately AU$78 per annum in capacity payments. It is reasonable to suppose that vehicles will not be fully charged at all times of the day, so we assume that as a worst case battery charge levels are well maintained and that the average state of charge of the participating vehicles at any one point in time is 10 kW h. Assuming a participant would keep some spare capacity for emergencies and some inversion losses, a 13 kW h battery may only have 6 kW h available at the time of dispatch, therefore the capacity payment might in reality be $36 per annum.

The University of Western Australia's electric vehicle battery pack holds 13 kW h of energy and has been experimentally shown to allow a driving range of 80 km. PHEV battery packs are currently substantially smaller, but have alternate fuel reserves so do not require an emergency reserve. For the purposes of this

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discussion, we will not distinguish between BEVs and PHEVs and will assume that all vehicles are BEVs.

It is reasonable to suppose that vehicles will not be fully charged at all times of the day, so we assume that as a worst case battery charge levels are well maintained and that the average state of charge of the participating vehicles at any one point in time is 10 kW h.

V2G schemes would in reality compete with traditional sources, such as peaking plant capacity. The returns calculated above ignore any required economic benefit for network operator to roll out the necessary infrastructure in order to enable the adoption of V2G, and the cost of an aggregator that would need to sit between vehicle owners and the market in order to administer the scheme.

V2G used for the supply of stored bulk energy looks extremely uncompetitive on an energy basis when compared with existing underutilised centralised generating capacity. In addition, the economic return to participating vehicle owners under the most generous of assumptions is negligible. Based on this analysis, it appears unlikely that vehicle-to-grid technology will be adopted in WA to supply any form of bulk energy requirement. Kempton and Tomic (2005a), who conducted a detailed analysis of the costs and benefits of the adoption of vehicle-to-grid technology, came to a similar conclusion, surmising from their analysis that vehicles probably will not supply bulk power, both because of their fundamental engineering characteristics and because the cost per kW h of energy from vehicles is higher than the cost of electricity supplied from centralised generators. They argued that for V2G to be able to compete, there therefore needs to be a capacity payment to encourage vehicle owners to regularly make their vehicles available, with an added energy payment when power is actually dispatched, as is the case for the sale of ancillary services by centralised generators. For those markets, they argued, losses made on energy sold would be more than made up for by the capacity payment. In addition, they considered that V2G may be able to compete when paid only for energy, but only when electricity prices are unusually high, as in some peak power markets. More recently, Dowds et al. (2010) concluded in their report that V2G is best suited to the supply of high value grid support services, such as frequency and voltage control.

Given the Reserve Capacity Mechanism, wholesale energy in Western Australia is traded based upon cost and the consumer is protected from price volatility. In a peak power market, as described above, spot prices tend to be highly volatile and may far exceed battery wear and tear costs talked about above, albeit infrequently. Peterson et al. (2010) studied three peak power markets in the United States in order to establish whether it would be viable for vehicle owners to use stored energy and so offsetting the need to consume peak energy from the supply system. While their underlying assumptions and methodology differs from that presented, the results are similar to those above.

6.4.7. *Supply of power—ancillary services*

Based on the above, high value ancillary services such as spinning reserve and regulation are the only possible uses for V2G technology in Western Australia, where payment is made on a capacity, rather than on an energy, basis. According to Western Power (2009a), in 2008/2009, Spinning Reserve cost a total of $24.71 million and Load Following cost a total of $9.82 million for the year. Enough spinning reserve capacity is required to cover 70% of the largest generation unit, Collie Power Station, which has an output capacity of 340 MW (Independent Market Operator, 2009a).

Stored battery power in vehicles batteries and electricity generated in real-time by vehicles could technically be delivered to the network in times of need. Both energy and capacity requirements would need to be met. This requires infrastructure investment, together with fleet of vehicles that is sufficiently large for a sufficient number of vehicles to be statistically available at any one point in time with enough overall energy to meet the need.

With respect to load following, Western Power (2009a), in its role as system management, stated that the service "*cannot be supplied from facilities such as interruptible loads that do not respond to continuous control signals*". That is, load following requires a dedicated communication link. Since real-time load management plays such a crucial role in maintaining a secure and reliable electricity supply, the system would need to be proven to be close to fail safe and to be able to operate under the conditions in which it would be most needed. For example, the communications equipment and meter may be required to operate under independent power, such as uninterruptible power supply.

It is currently too early to accurately predict the cost of purchasing and installing the necessary equipment, management systems and network to extend smart grid functionality to meet the requirements set out above for the supply of spinning reserve and load following. Instead, we can look at what is currently spent on these services and how this budget could be divided up to pay for the service supplied from a V2G solution.

For spinning reserve, a total capacity of 285 MW is currently required in Western Australia's SWIS. In their cost benefit analysis, Kempton and Tomic (2005a) assumed that the service is required for at most one hour. For comparison, we adopt this assumption and therefore 285,000 kW h must be supplied. Based upon Table 5, this can be supplied by 47,500 vehicles. Finally, we can assume that in the worst case, 20% of vehicles are on the road during the rush hour, and that a minimum of 80% of participating vehicles are grid connected and available for a V2G transaction at any point in time. The required number of participating vehicles is therefore approximately 60,000.

We are now able to estimate an annual budget per participating vehicle for two scenarios (Table 6).

In the first scenario, participating vehicles supply spinning reserve only and communications could be supplied by a low cost wireless or 3G service.

In the second scenario, vehicles are used to supply load balancing as well as spinning reserve, and communication is therefore upgraded to a more reliable copper service. The assumption that a single point of communication would be required per participating vehicle (in the home) is a reasonable approximation. Vehicles would require V2G transaction points in public car parking facilities in order to meet an assumption that 80% of vehicles are available at any point in time. This would therefore require more than one point of connection per participating vehicle. However, since charging points additional to the home would likely be densely situated in, for example, public car parking facilities, the required communications links would likely be aggregated over a single line, therefore making the cost of additional network points negligible.

It seems unlikely that the annual capacity payments of $216 would provide sufficient encouragement for vehicle owners to participate in such schemes in great numbers (Table 6). The vehicle owner would have to purchase a power convertor capable of bidirectional power flow. In addition, an aggregator would need to sit between the vehicle owner and the market and would

Table 5
Available energy per vehicle at time of dispatch (kW h).

Battery capacity (kW h)	13
Battery charge level at time of dispatch (kW h)	10
Emergency reserve (kW h)	4
Total energy available per vehicle (kW h)	6

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Table 6
Estimated annual capacity budget per vehicle participating in the provision of ancillary services.

Ancillary services budget ($)	Spinning reserve only	Spinning reserve and load balancing
Spinning reserve budget ($)	24,710,977	24,710,977
Load balancing budget ($)	0	9,823,019
Total annual budget ($)	**24,710,977**	**34,533,996**
Annual budget per participating vehicle ($)	412	576
Annual communication budget per vehicle ($)	30	360
Annual capacity budget per participating vehicle ($)	**382**	**216**

need to cover costs as well as making some profit. Furthermore, the utility would be required to invest in a management system and possibly in meter upgrades to control the scheme. These requirements marginalise the opportunity further and it would be unlikely to meet the investment criteria imposed upon the utility as they currently stand and as outlined above.

6.4.8. *Supply of demand management*

The minimum smart meter functionality agreed to by the Ministerial Council on Energy will support demand management. This functionality has already undergone testing by Western Power, originally for the purpose of controlling of air-conditioning units in times of very high peak demand or supply failure.

Adding plug-in electric vehicles to the load shedding options would bring further benefits to the demand management program already in trial. Interrupting a four-hour charge cycle that has between, say, 10 pm and 7:30 am to be completed would have a minimal, if any, effect on the vehicle owner. If the vehicle is also charged while parked at work, then interrupting two two-hour charge cycles would again have a very small, if any, impact on the vehicle owner. Lithium ion batteries do not suffer the "memory" issue of earlier battery technologies, such as nickel metal batteries. This application would have little, if any, effect on the expected life of the lithium ion battery pack, and there would therefore be no requirement to provide compensation for wear and tear.

Using EVs for this purpose would be highly attractive as it few industrial customers have proved willing to receive payments to have their loads interrupted, as demonstrated by the specific mention of the extension of a 10 MW interruptible contract in Western Power's Ancillary Services Report 2009 (Western Power, 2009a).

Since it is expected that plug-in electric vehicles will be at least 1.5 kW systems, 52 MW of interruptible load can be obtained from a mere 35,000 vehicles or 2% of the total vehicle fleet in Western Australia. Aggregating vehicle owners via the retailer would be a simple task and participation could be achieved though incentives such as offering a discounted tariff to participants.

In addition to the advantages above, demand management enables system management to coordinate and shape demand, allowing for utilisation improvements. Demand management undertaken during the day would ensure that vehicles are not charging during the daytime peak, especially during the summer months. This would serve to make the industry more profitable, while offering the ability to shed or introduce demand, as applicable, in time in the event of a sudden system failure on the supply or demand side of the network.

7. Alternative options

Many V2G analyses treat V2G technology as the only available storage option and overlook the fact that there are alternatives available to the electricity supply industry that make as much or more sense. In addition to the traditional rapid start gas fired generation capacity already in use, four competing energy storage options are briefly discussed, in ascending order of costs, below.

7.1. *Pumped hydroelectric storage*

As discussed already, in markets where hydroelectric storage is available, this is likely to be a lower cost energy storage option than the V2G option. The fact that electricity companies have used this option wherever it is available, indicates the value placed on storage by the electricity supply industry

7.2. *Thermal energy storage systems*

Where direct solar energy radiation levels are high, such as in much of Western Australia, much of North America, and North Africa solar energy, can be concentrated and stored in various forms. Storage of thermal energy de-couples the collection of solar energy from the production of electricity. The most common form of storage coupled to concentrating solar power systems used today is as sensible heat in large, binary molten 'solar' salt storage systems. The tanks containing the molten salt mixtures are well insulated and the energy can be stored for up to a week. The storage systems built to date have typically had sufficient thermal storage to power a 100 MW turbine for up to four hours and have comprised tanks 30 feet tall and 80 feet in diameter. Studies show that the two-tank storage system could have an annual efficiency of about 99% (Sena-Henderson, 2006). However, as technologies for storing the salts at higher temperature are developed and single thermocline storage tanks are developed, the tank storage size decreases and the thermal storage capacity increases. Teagan (2001) compared the costs ($/kW h) of molten salt storage with that of batteries and reported that the costs of molten salt storage to be 20–30 times lower than battery storage and the lifetimes to be 3–6 times longer. Both battery technologies and molten salt storage systems have advanced significantly over the last 10 years. Terrasolar, for example, has recently commissioned a 20 MW system with 15 h storage capacity (Lata et al., 2010).

Concentrating solar thermal energy systems with molten salt storage are expected to become competitive with conventional peak and intermediate electricity generation by 2020 and with base load generation by 2025–2030 (Philibert, 2009), which is approximately the same timeframe that a sufficiently large number of EVs would have entered the market to make a V2G option viable. The advantage of solar thermal energy storage systems is that they can be scaled to meet the requirement and would not suffer the same wear issues that hamper lithium ion batteries.

7.3. *Flywheels*

On a smaller scale, utilities in Western Australia use the kinetic energy stored in a spinning flywheel for short periods of time. For

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example, Horizon Power owns and manages generating facilities that supply power to small communities in outback Western Australia. At Marble Bar and Nullagine, Horizon has installed solar/diesel hybrid generation facilities that use flywheels to smooth the fluctuating solar power (Horizon Power, 2009). Verve Energy also owns a wind/diesel hybrid facility to supply power to the Coral Bay community that uses a flywheel to buffer the fluctuating wind supply (Verve Energy, n.d.). These are costly and best suited to small remote power systems.

7.4. Dedicated battery banks

If there was a commercial advantage available to vehicle owners to supply stored power from their vehicle batteries, then the same would apply to an entrepreneurial operator looking to install one or more distributed battery bank facilities at key points on the network, such as in or next to substations. Purchase batteries in large quantities direct from the manufacturer, the battery bank owner would have a buying advantage over vehicle owners who purchase small quantities of batteries via a vehicle manufacturer. In addition, there would be no need for an aggregator to sit between the battery owner and the market. A dedicated battery bank would also offer a service that would be guaranteed to be available 100% of the time. The advantage of a dedicated battery bank strategy to the network operator would be that there would be only a handful of interconnections to the grid and the system would therefore require a communication network and a management system that would be more secure, and only a fraction of the size, complexity, and the cost of a highly distributed V2G system. In fact, A123 Systems, a company supplying batteries to a growing number of manufacturers and proving to be a driving force in battery technology, has recognised the potential of this market and has released a battery banking product called "The Smart Grid Stabilisation System" which is scalable to 200 MW (A123 Systems, 2011).

8. Conclusion

The notion of V2G is without doubt very appealing. And at first glance it is in many ways compelling. However, when looked at in more the detail, the economics and the practical complexities involved in implementing some of the different V2G scheme variants show that they currently lack commercially practicality.

The idea of the vehicle-to-grid (V2G) technology is underpinned by the notion that electric vehicles represent a distributed and underutilised energy storage facility and in the case of plug-in hybrid electric vehicles (PHEVs) a source of electricity generation. In aggregate, the electricity storage capacity offered by 1.8 million electric vehicles is significant and available most times during the day. This is especially appealing to a grid such as that of Western Australia, which has an isolated grid with no traditional large-scale electricity storage option.

On the one hand, the cost of battery wear pushes V2G towards low utilisation ancillary services where although capacity is normally available it is seldom actually used. This means that the available capacity payment will pay for that damage. If rarely used, however, it is difficult to justify the expense of any supporting infrastructure. This makes V2G uneconomic at present time in comparison conventional generation or alternative storage options, such as battery banking which is a competing scheme using the same or better technology without lower infrastructure costs.

V2G scheme based on using vehicles as either a storage devices or generators would introduce risk for both industry and individual, and would offer few if any benefits over lower cost and more practical alternatives that are or that are likely to become available within the same or shorter timeframe that V2G becomes a viable option. Given the regime under which the local industry investment decisions are made, the commercial benefits of any V2G scheme, over all other alternative options, would have to be clear cut. Currently, this is not the case for most vehicle-to-grid schemes. A significant reduction in future battery costs would benefit equally benefit V2G and the battery bank alternative.

One scheme, however, is highly feasible and would provide significant benefits—that of demand management. This is a scheme that will utilise standard functionality of smart meters and the communications and control systems that will be put in place for a smarter grid, and is already taken seriously on a worldwide basis by grid operators who are trialling the management of different loads. The addition of new types of loads to those schemes would make those more attractive and robust.

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