A STUDY OF OPTIONS FOR THE DEPLOYMENT
OF LARGE FUSION POWER PLANTS

John Sheffield 1
William Brown 2
Gary Garrett 3
James Hilley 2
Dennis McCloud 3
Joan Ogden 4
Thomas Shields 2
Lester Waganer 5

1 Oak Ridge National Laboratory and JIEE
2 Duke Engineering & Services
3 Tennessee Valley Authority
4 Center for Energy and Environmental Studies, Princeton University
5 The Boeing Company

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Joint Institute for Energy and Environment
314 UT Conference Center Building
Knoxville, TN 37996-4138
Phone: (865) 974-3939
Fax: (865) 974-4609
URL: www.jiee.org
e-mail: jiee@utk.edu
Abstract

One option for making fusion power plants that could be competitive with other power plants operating during the 21st century is to make them large, e.g., 3GWe or more, to take advantage of the expected economies of scale. This study examines the effects on electrical utility system hardware, operations, and reliability of incorporating such large generating units. In addition, the study evaluates the use of the co-production of hydrogen to reduce the grid supplied electricity and offer the possibility for electrical load following.

The estimated additional cost of electricity for a large power plant is about 5 mills/kWh. The estimated total cost of electricity for 3-4 GWe fusion power plants lies in the range of 37-60 mills/kWh.

Future hydrogen costs from a variety of sources are estimated to lie in the range of 8-10 $/GJ, when allowance is made for some increase in natural gas price and for the possible need for greenhouse gas emission limitations.

A number of combinations of fusion plant and electrolyzer were considered, including hot electrolyzers that use heat from the fusion plant. For the optimum cases, hydrogen produced from off-peak power from a 3-4 GWe plant is estimated to have a competitive cost. Of particular interest, the cost would also be competitive if some hydrogen were produced during on-peak electricity cost periods. Thus, for a 4 GWe plant, only up to 3 GWe might be supplied to the grid, and load-following would be possible, a benefit to the utility system.
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1. Introduction

This study evaluates the effects of large fusion-powered generating units (e.g. 3 GWe or more) on electrical utility system hardware, operations, and reliability. This is an important consideration for projected fusion energy systems that, presently, show better economics at large size.

Studies of fusion power plants using magnetic or inertial confinement have shown an economy of scale, e.g., the ARIES studies (Miller et al. 1996 (1) and 1999 (2), ARIES-RS and ARIES-AT, respectively), Galambos et al. 1995 (3), Hender et al. 1996 (4), Sheffield et al. 1996 (5), Zuckerman et al. 1988 (6). However, most power plant design studies have focused on the 1 GWe range because such a plant size is more commonplace and at smaller sizes it is harder to meet the physics, technology, and engineering requirements. At the larger size, not only should the cost of electricity (COE) come down, but it should also be easier to accommodate the volume needed for plasma clearing systems and the access needed for cooling and maintenance. The use of fusion energy to generate products other than electricity has also been considered, and hydrogen production is an attractive opportunity, e.g. Kulcinski 1996 (7), Logan 1993 (8), and Wagener et al. 1997 (9). The concept of a “hydrogen economy” is of great interest, e.g. Johansson et al. 1996 (10), Socolow 1997 (11), and Williams 1996 (12); it should offer a cleaner and healthier environment for future generations.

This study adds to the previous work by addressing two questions:
1. From a utility perspective, what are the consequences of deploying large, single-unit power plants, e.g. 3 GWe or more?
2. Would the use of co-generation—in this case electricity plus hydrogen production—improve the prospects for the deployment of large fusion power plants?

Note that the question of whether, or under what conditions, utilities would want large power plants is not being discussed in this study. Deployment of fusion energy is far enough in the future that it is difficult to predict either the utility or independent system operator situation, or their interest in large plants.

Economy of scale studies for both magnetic and inertial fusion power plants show the cost of electricity decreasing with increasing electrical capacity, approximately as $(P_e/P_{eo})^{-0.35}$ in the range of interest. Consequently, while a typical 1,000 MWe fusion plant might produce electricity at 50 to 90 mills/kWh, a 4,000 MWe plant might produce at 32 to 50 mills/kWh (see Table I).

<table>
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<tr>
<td></td>
<td>1,000</td>
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<tr>
<td>ARIES-RS</td>
<td>87</td>
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<td>ARIES-AT</td>
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The ARIES-RS power plant was completed in 1996 with costs reported in 1992 dollars (1). These costs have been updated to 1999 dollars. Additionally, for this study, the ARIES Systems Code projected the performance and cost of the ARIES-RS plant up to the 4 GWe size. It should be noted that no optimization for the larger size was accomplished—the plants were merely scaled up with a constant wall load constraint. To assess other possible improvements, the ARIES group has since commenced a new design and evaluation effort of an advanced tokamak reactor, the ARIES-AT (2). The work is ongoing at the present, but some preliminary data is available and is included in this study to indicate the possible improvements. ARIES-AT has a more efficient plasma, with higher triangularity and elongation to yield higher beta values. A new, higher temperature blanket design has been incorporated that yields much higher thermal conversion efficiency. Efforts are underway to significantly lower the capital cost of the power core components. It is also anticipated that the plant availability can be raised to help lower the average cost of electricity. The combined effects of these improvements enable the AT’s cost of electricity to be lower than the RS’s. The range of cost of electricity from both plants is pictured in Fig.1.

The data above represent the daily average cost of electricity, fully burdened with annualized capital cost and all operating costs. These figures may be compared with today’s spot price for electricity in the U.S., which typically varies in the range of 15 to 60 mills/kWh. The lower value in this range is usually associated with off-peak times. Average prices are lower in some areas, e.g., 25 mills/kWh in California (13), generally because capital costs have been liquidated or are accounted for elsewhere (stranded costs). In these situations, the cost of electricity (COE), charged by the power provider, reflects only the operation, maintenance, and fuel costs, while annual capital mortgage payoffs are excluded.

This study compares fusion with systems in which the capital cost is still outstanding. Some fuel prices will increase over the next century; and this, along with environmental improvements, will increase the COE for both fossil and nuclear fission plants. However, technological advances and improved efficiency of electricity production should tend to offset these increases. On the other hand, a requirement to reduce carbon dioxide would increase the cost of fossil generated electricity if carbon sequestration is required. Allowing for these factors, a separate study estimated the possible range of COE ($1999) for new 1,000 MWe or less power plants in the 2050 time frame (14). These COE projections are provided Table II. These ranges account for varying fuel prices and assume that nuclear waste disposal issues have been settled. The cost of carbon sequestration is assumed to be $50/tonne.

Since the COE from 1,000 MWe fusion plants is projected to be in the range of 50 to 80 mills/kWh, it is prudent to understand how the larger unit size plants, with lower COE values might be able to operate competitively in this future energy market. For electricity to be useful it is necessary to “guarantee” that the power will always be available. Assurance of this capacity for plants exceeding the conventional up-to-1-GWe level will require substantial investment in both spinning and ready reserve power. Smaller generating plants have the advantage that smaller spinning and ready reserves are required, and these reserves can be shared by many smaller power plants. Conversely, a plant significantly larger than the norm will require unique and large generating capacity reserves and additional capital investment.
Fig 1. Projected range of costs for ARIES-RS and ARIES-AT, by plant size, excluding additional utility costs.

Table II

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<th>Plant Type</th>
<th>Low-end Estimate</th>
<th>Upper-end Estimate</th>
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<tr>
<td>Coal w/o sequestration</td>
<td>31</td>
<td>45</td>
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<tr>
<td>Coal with sequestration</td>
<td>54</td>
<td>61</td>
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<tr>
<td>Natural gas w/o sequestration</td>
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<td>Natural gas w/ sequestration</td>
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<td>73</td>
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<td>ALWR</td>
<td>37</td>
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The co-production of electricity and hydrogen in a large power plant offers the possibility of a lower electricity production cost, while reducing the increment of power subject to an investment in spinning and ready reserve power. The co-production of hydrogen should allow the flexibility in operation of load-following. Therefore, the examination of co-generation of hydrogen and electricity is of interest.
2. System and Operating Effects of Large Power Units

2.1 System Requirements for Incorporating Large Unit-size Power Plants

Electrical utilities plan and operate their systems to meet the daily variation of electricity demand including the peak load forecast. However, emergencies—including generator outages—can prevent certain resources from operating when needed. The inability to make perfect generation and transmission systems leads to outages and the interruption of electric service to the customers. System capacity is needed, therefore, to provide a reserve margin to ensure adequate power is available. The optimum system reliability is the point at which the incremental power system costs of increasing reliability and incremental customer outage costs are equal.

Even with the uncertainty in the timing of peak loads and unit-forced outages among interconnected utilities, surplus power has usually been available from the interconnections on a spot basis. Currently, there are some bottlenecks in this open exchange of power, but these constraints should be eliminated in the future.

In the real-time, a utility must carry enough operating reserves to cover the loss of its largest, currently generating unit, plus an additional amount (e.g., 200 MWe) for regulating purposes. Of this power, a portion (e.g., 50%) should be in spinning reserves that are capable of instantaneous increase to meet the unexpected situation. The remaining reserves should be capable of being synchronized to the system and carrying load within 10 minutes. Sharing spinning reserves within the interconnection could only be accomplished by the use of dynamic scheduling techniques on firm transmission service paths reserved by the participating parties. This limits the number of participants in such an interconnection, leading to a greater probability of a simultaneous need for shared reserves, and thus reducing the benefits. For supplemental reserves dynamic scheduling would not be needed, but firm transmission service would still be required between the participants, again limiting possible participation.

Thus, system protection reserves include spinning and fast start generating equipment that can be fully available within 10 minutes. This protection would correct for generation and load imbalances caused by generation and transmission outages. Supplemental and operating reserves through the use of generating equipment and interruptible load can be fully available within 30 minutes to back-up the 10-minute reserve.

The reserve margins may be calculated using methodologies such as the Hourly Loss of Load Expectation (HLOLE) model (15). This type of model accounts for items such as:

a) Projected hourly load for the future, based on normal weather,
b) Amount of interruptible power contracts within the forecast,
c) Generating unit capacity level,
d) Equivalent forced outages, which include both forced outages and de-ratings of generator capacity,
e) Generating unit planned and maintenance outage rates,
f) Generating unit de-rated steps
g) System reserve requirements such as spinning, supplemental, and other reserves,

h) Cost of outage by class of customer and duration of outage, and

i) Inter-tie capability of transmission system interconnections with other utilities and available transfer capabilities.

For larger utilities, such as Duke Power and TVA that operate plants up to a scale of 1,300 MWe, the operating reserves are about 1,500 MWe. One half of the operating-reserves criterion must be met by spinning reserves of about 750 MWe.

If a 3,000 MWe plant were added, the operating reserves would have to be increased to 3,200 MWe and the spinning reserves to 1,600 MWe. In addition, a fusion plant restart at peak demand times might require an additional 200 to 350 MWe. This requirement could be met by the spinning reserves.

The operating reserves include excess generating capacity to deal with scheduled downtime and are about 15%, typical of North American utilities. Note that this is down from the value several years ago of around 20%. The trend in the industry is to even lower levels, which would make unit reliability more critical and would exacerbate the problem of introducing larger plants.

The maximum unit size that would not create severe generating reliability impacts is on the order of 5–8% of the system size.

2.2 Unscheduled Power Loss Levels

It is customary to size the operating reserve to deal with a loss of power from the largest, single-unit power plant. However, because of electrical failures, clusters of plants may be disconnected. To date, the worst unscheduled loss for Duke Power was an electrical failure involving two generating plants that disconnected 2,250 MWe. At TVA, a tornado cut power lines and disconnected two 1,200 MWe units. At that time, other plants at the site were not operating. This kind of event is viewed as sufficiently rare, compared to a single-unit failure and is not considered explicitly in establishing the operating reserves.

2.3 Utility-size Cases

Bearing in mind the comments above, a consideration of the innate ability of different size utilities to handle large power plants suggests that:

a) A small utility system (5,000 MWe) would not be able to handle a 3 GWe or larger power plant.

b) A large utility system (15,000–25,000 MWe), using the 5 to 8% measure of maximum plant size compared to total utility capacity, should be able to accommodate a new generating plant up to 2,000 MWe, and possibly somewhat more; but increased operating reserves would be required. Thus, for a new plant of this size, hydrogen co-production would be desirable to reduce the grid-supplied electricity and handle the larger plants.

c) A large Independent System Operator (ISO) (50,000 MWe) could handle a 3,000–4,000 MWe plant within existing capabilities. A trend in the industry is for mergers and larger transmission and operating grids [e.g., as seen in the FERC Order 2000, regarding Regional Transmission Organizations (16)], making larger systems more common.
2.4 Types of Generating Units Needed on a Power System

The four basic types of power generation are

a) Peaking Units: These units can respond quickly to changes in system power demand. They normally only operate for short periods of time when demand for power is very high. A gas-fired turbine is a common example. Peaking units generally have the lowest capital cost and highest operating costs.

b) Intermediate Units: These are designed to meet the next highest level of power demand. They have some of the same characteristics as peaking units since they must start and stop often and generate a wide range of power outputs. A gas-fired combined cycle plant is an example.

c) Base-Load Units: These units provide a largely constant level of power demand and tend to be cycled on and off far less frequently than peaking or intermediate units. A nuclear plant is an example. Base-load units usually have high capital costs and low operating and fuel costs.

d) Storage Units: These units serve the same power supply function as peaking units, but also use low cost, off-peak electricity to store energy for peak times. A hydro-pumped-storage plant is an example. A combustion turbine or combined cycle plant using stored hydrogen would also be considered in this class.

A large fusion plant, because of its large capital cost, compared to operating cost, would best fit in the base-load category, even if it allowed some variation in output. Temperature cycling of the blankets in fusion power plants must be limited to minimize cyclic fatigue problems. However, electricity supply to the grid could be modulated if the excess electricity were used, at constant plant electricity output, for some other purpose, e.g. electrolytic hydrogen production (see below). Such a plant might be built to supplement existing capacity in a growing electricity market and/or to replace an older plant. Depending on which generation plant were replaced, voltage and frequency dip problems might be increased due to the need for evenly and strategically distributed VAR support. Though the additional cost is not expected to be large, further evaluations may be needed. In addition, thermal and voltage contingency problems might limit the ability of a system to take lines out of service for maintenance and construction activities.

2.5 Typical Load and Supply Characteristics for a Large Utility

Utility load and power supply levels typically vary both daily and seasonally, depending on the climate and the customer demands. Some utilities, such as TVA, typically experience two distinct seasonal load patterns that establish their extreme load demands.

Figure 2 illustrates one of TVA’s typical winter load and supply curves. This demand curve has two daily peaks, one in the early morning and one in the evening when heating demands reach their maximum level. These peak demands are met by increasing the output of all plants and bringing on line the pumped storage units. Interconnection net purchases are avoided if possible during these periods due to the high spot price of power. The outputs of the nuclear and coal plants remain nominally at their steady base-load level.
A completely different load and supply curve is observed in the summer period, as shown in Figure 3. Here, the air conditioning load demand is the dominant factor, peaking in the afternoon and early evening and reaching its lowest demand in the early morning. Again, nuclear plants remain at their steady base-load level. The coal plants only reduce output during the early morning hours. All other utility plants increase their output to satisfy the demand during the peak period. The combustion turbines and the storage units are turned on to help meet the demand. If these combined assets are insufficient, power is purchased from the interconnection net. Net purchases are usually the highest cost of power.

### 2.6 Industry Experience with Large Generating Sites

There are some utilities worldwide that have large generating resources at a single site. Large hydroelectric dams and groups of nuclear or coal plants, for example, can house thousands of megawatts of generating capability. In such cases, the transmission system must be even more secure and ‘redundant’ so that an outage does not take out extremely large amounts of electrical supply from the system. Another consideration for the transmission system is that the plant would need enough transmission support to maintain generator stability during disturbances on the transmission network. The plant transmission requirements depend on generator, site, and other system characteristics.
Bonneville Power Administration has a single site at the Grand Coulee Dam consisting of 33 generating units that total over 7000 MWe. At Grand Coulee, the units range in size from 10 MW to 700 MW on a system that has a peak load of around 30,000 MW. Transmission considerations are obviously more constraining than generators since there no single, large unit.

### 2.7 Turndown and Other Operational Issues

Turndown Issues - Unit ‘turndown’ is necessary so that the total generating capacity of the electric system can follow the hourly patterns of the load demands. At night, when loads are at a minimum, generating capacity must be reduced or turned down, yet adequate supply must be available during the peak on the following day. Some coal-fired units are capable of responding to this need to ‘turn down’ by operating at a minimum level during the off-peak hours and at full capacity during peak conditions (see Figs. 2 and 3). Combustion turbines are extremely valuable as ‘turndown’ units since they can be turned off and on daily as needed. Pumped storage capacity offers the best turndown capability simply because it stores additional capability during the off-peak period at low COE and generates electricity during the high cost periods. Very large units with massive amounts of thermal capacity are not turned down very often simply due to thermal ‘momentum’. A 3000
MWe or larger fusion unit would not be turned down very often. This unit would be on line ‘around the clock’, providing electrical power to the grid, except for emergencies or for maintenance. Some other type of generating capacity would have to be capable of turning down during off-peak times. However, greater flexibility for a large fusion plant would result from co-generating hydrogen or supplying a pumped storage system, while supplying a variable amount of electricity to the grid (14).

Load Following and Regulation - A similar electrical concept is the capability of generating capacity to actually ‘follow’ the load on an instantaneous basis or regulate through the use of governors and automatic generation control that allow tracking moment-to-moment fluctuations and the hourly trends in customer loads. Load following helps maintain interconnection frequency and generation and load balance within the control area. A very large unit would be unlikely to have this capability whereas smaller generating units could be equipped to handle this need.

2.8 Reliability
To obtain good system reliability, every feed in the switchyard should go to two breakers (breaker and a half system) so that one breaker going down does not affect reliability. Using the N-2 criterion, one can operate at full power even with two lines to the main transmission system out of service.

Studies of the availability of different size thermal generating plants, from 100 MWe to greater than 1,000 MWe, show relatively little variation in reliability. Typically, the availability for these plants is in the range of 80% to 85%, with about 5% unscheduled (17). The main difference for a larger plant, compared to a number of small plants of the same total output, is that when the large one is down all of the electricity is unavailable.

For example, consider the cases of 10 x 300 MWe units compared to 1 x 3,000 MWe unit, with both cases having 10% scheduled and 5% unscheduled downtimes for a total availability of 85%. By definition, each example will produce the same amount of electrical energy, however:
- For 10 x 300 MWe units, there is a 10% probability that two units could be down — each unit will be scheduled down in rotation and 5% of the time a unit could be down randomly. It is unlikely that three units could be down. Thus, the output power would lie between 2,400 MWe and 2,700 MWe.
- A single 3,000 MWe unit, with the same 85% availability, is either on or off. To handle the unscheduled off-time requires more guaranteed back-up power.

As discussed in Section 2.1, to add a 3,000 MWe plant to systems such as Duke Power and TVA, the spinning reserves would have to be increased from about 750 MWe to 1,600 MWe and the operational reserves from 1,500 MWe to 3,200 MWe. With combustion turbine prices around $300/kW, the new spinning reserves would require an additional capital cost of about $255 million. With a repayment of capital of 10% per year, fixed charge rate over 20 years, this element of capital investment would raise the plant cost of electricity by about 1.2 mills/kWh.

In terms of the loss of power, it might be argued that for some part of the 5% unscheduled downtime it would be necessary to purchase electricity to cope with the loss of such an unusually large amount of power, beyond that which could be handled readily by the system. This would
likely be the case during peak demand times. Assuming a cost of 50 mills/kWh, for half of the unscheduled downtime, the incremental cost would be $33 million for a 3,000 MWe unit.

2.9 Siting Costs

Cost estimates for substations and lines are shown in Table III. A general advantage accrues with larger unit size for certain kinds of components, considered in the assessment of COE versus electrical power output. The costs scale roughly the same as the base cost for the 1000 MWe plant.

Table III

<table>
<thead>
<tr>
<th>Generation Option</th>
<th>Substation Cost</th>
<th>Transmission Line Cost</th>
<th>Total Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>1000 MWe</td>
<td>$26,000,000</td>
<td>$105,000,000</td>
<td>$131,000,000</td>
</tr>
<tr>
<td>2000 MWe</td>
<td>$42,000,000</td>
<td>$140,000,000</td>
<td>$182,000,000</td>
</tr>
<tr>
<td>3000 MWe</td>
<td>$59,000,000</td>
<td>$175,000,000</td>
<td>$234,000,000</td>
</tr>
<tr>
<td>4000 MWe</td>
<td>$76,000,000</td>
<td>$210,000,000</td>
<td>$286,000,000</td>
</tr>
</tbody>
</table>

Table IV

<table>
<thead>
<tr>
<th>Site A:</th>
<th>Distance</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Loop connections</td>
<td>33.8 km (21 miles)</td>
<td>$15M</td>
</tr>
<tr>
<td>Transformers and other equipment</td>
<td></td>
<td>$46M</td>
</tr>
<tr>
<td>Estimate Total</td>
<td></td>
<td>$61M</td>
</tr>
<tr>
<td>Site B:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Loop connections</td>
<td>132.0 km (82 miles)</td>
<td>$56M</td>
</tr>
<tr>
<td>Transformers and other equipment</td>
<td></td>
<td>$46M</td>
</tr>
<tr>
<td>Estimate Total</td>
<td></td>
<td>$102M</td>
</tr>
</tbody>
</table>

Incremental costs for transmission for a 3,000 MWe plant placed on an existing site were evaluated for two typical TVA sites (see Table IV). The incremental costs were in the range of $60–100 million. This cost estimate does not include the cost to restore other transfer capabilities that may be affected on other transmission paths. These additional costs could double the estimates shown here. These TVA-based costs compare to the roughly $100M incremental cost for the Duke system to go from 1000 MWe to 3000 MWe. In addition, there are issues today of getting approval to increase transmission capability. Therefore, it is important to site large plants where the grid is already strong. In summary, for a 3,000 MW plant the siting costs at an existing 1000 MWe site...
may lie in the range of $60–160 million. For the purposes of this evaluation, a typical cost of $100 million will be used.

### 2.10 Production Cost Impacts

Production cost simulations were also made to determine differences in generating unit dispatch impacts of the large unit. These simulations do not include the impact of load following and two-shift requirements.

Differences in spinning reserve and total operating reserve requirements, as well as the manner in which other generating units on the system must operate, could increase operating costs between $30 million and $150 million depending on plant size (see Figure 4). These cost estimates do not include any fuel cost benefits that will offset some of these other costs. Production cost savings due to pure dispatch have not been determined nor considered in this review.

![Operating Cost vs. Size of Unit (MW)](image)

**Fig. 4.** Impact of unit size on TVA generating system operating costs.

### 2.11 Overall Incremental Costs

For the case of a 3,000 MWe plant, the costs include:
- Capital costs for reliability of $255 million for spinning reserves (see Sect. 2.8), plus an incremental site cost of $100 million (see Sect. 2.9).
- Incremental operating costs of about $30 million per unit per year (see Sect. 2.10)
- Cost of purchased electricity during peak, unscheduled downtime at $33M per year (see Sect. 2.8).

Assuming a 10% capital payback per year of investment over 20 years, the annual cost would be approximately $100 million for a 3,000 MWe unit (see Table V). With a capacity factor of 85%, this unit would add about 4.4 mills/kWh. Incremental and total costs of electricity costs for other unit sizes are shown in Table V for both the ARIES-RS and the ARIES-AT.
Table V. Range of Incremental and Total Costs for Fusion Power Plants

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>Unit Size (MWe)</th>
<th>1000</th>
<th>2000</th>
<th>3000</th>
<th>4000</th>
</tr>
</thead>
<tbody>
<tr>
<td>Extra Spinning Reserve ($M/y)</td>
<td></td>
<td>0</td>
<td>10.5</td>
<td>26.0</td>
<td>40.5</td>
</tr>
<tr>
<td>Incremental Site Cost ($M/y)</td>
<td></td>
<td>0</td>
<td>5.0</td>
<td>10.0</td>
<td>15.5</td>
</tr>
<tr>
<td>Inc. Operational Cost ($M/y)</td>
<td></td>
<td>0</td>
<td>15.0</td>
<td>30.0</td>
<td>60.0</td>
</tr>
<tr>
<td>Purchased Electricity ($M/y)</td>
<td></td>
<td>0</td>
<td>22.0</td>
<td>33.0</td>
<td>44.0</td>
</tr>
<tr>
<td>Total Extra Annual Cost ($M/y)</td>
<td></td>
<td>0</td>
<td>52.5</td>
<td>99.0</td>
<td>160.0</td>
</tr>
<tr>
<td>Incremental COE * (mills/kWh)</td>
<td></td>
<td>0</td>
<td>3.9</td>
<td>5.0</td>
<td>6.0</td>
</tr>
<tr>
<td>Incremental COE ** (mills/kWh)</td>
<td></td>
<td>0</td>
<td>3.5</td>
<td>4.4</td>
<td>5.4</td>
</tr>
<tr>
<td>ARIES-RS COE *** (mills/kWh)</td>
<td></td>
<td>87</td>
<td>68</td>
<td>60</td>
<td>56</td>
</tr>
<tr>
<td>ARIES-AT COE *** (mills/kWh)</td>
<td></td>
<td>51</td>
<td>44</td>
<td>39</td>
<td>37</td>
</tr>
</tbody>
</table>

* An availability of 76 % was assumed for ARIES-RS
** An availability of 85 % was assumed for ARIES-AT
*** Value derived by adding the incremental COE to the values in Table I.
3. Assessment of Fusion Applications

3.1 Introduction
The application of controlled thermonuclear fusion for the purpose of generating large amounts of electrical energy has been the vision of energy planners for nearly 50 years. The fusion energy released from a small amount of fuel is very large as was demonstrated in the early 1950’s. The energy potentially available from fusing hydrogen isotopes is enormous. However, the promise of a practical use for this energy has yet to be fulfilled, and recent cost projections of fusion-generated electricity costs are on the higher side of those predicted for near term, existing energy sources (1).

Encouraging progress has been made, and the larger experiments have moved the characteristic time, temperature, and pressure parameters toward the breakeven point, at which fusion energy produced equals energy input to the plasma. Pushing to higher quality fusion plasmas has been possible because of advances in all aspects of plasma physics and in the many technologies and materials that support these experimental devices. Nevertheless, it is anticipated that it will be decades before a practical fusion system is realized.

Fusion systems studies have been crucial in guiding research and development in a direction that would lead to fusion becoming a more viable energy producer, principally of electrical power. However, the studies are limited by current fusion knowledge, and the playing field conditions for all forms of power generation are continually changing—new technology developments are emerging, environmental pressures are increasing, and evolving geo-political influences will redirect the worldwide energy priorities. In these circumstance it is worthwhile considering what other applications of fusion energy might be attractive, particularly, because fusion energy does have some most attractive features. These are: the advantage of a huge fuel supply; siting the facility is not dependent on natural resources, and it will have no weather limitations; it will have a high level of safety assurance; and it will be well suited for producing large amounts of power.

3.2 Potential Fusion Applications
The conversion of mass into energy by the fusion process yields a variety of energy carriers that can be utilized to produce a multitude of products. The fusion fuel that is used in most burning plasma experiments and reference fusion power plants contains deuterium (D) and tritium (T). When these elements are fused they release high energy, 14 MeV neutrons, energetic alpha particles (\(^{4}\text{He}\)) at 3.5 MeV, and a range of electromagnetic radiation. Advanced fuels, such as deuterium with helium three (\(^{3}\text{He}\)), require a higher level of technology and would produce more charged particles and radiation but fewer (or practically no) high-energy neutrons.

Fusion as a source of very high temperatures, high-energy plasmas, and energetic particles can be used not only for electricity production but also to dissociate dangerous chemical compounds or transmute long-lived radioactive fission products. Fusion can create new or modify existing chemical compounds and in doing so can produce abundant supplies of clean-burning hydrogen—an important energy carrier if it is necessary to slow or reverse the greenhouse effect.
Table VI. Potential Fusion Products

<table>
<thead>
<tr>
<th>Neutrons</th>
<th>Charged Particles</th>
<th>Radiation</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Hydrogen</td>
<td>• Hydrogen</td>
<td>• Hydrogen</td>
</tr>
<tr>
<td>• Process heat</td>
<td>• Waste processing</td>
<td>• Waste sterilization</td>
</tr>
<tr>
<td>• Rocket propulsion</td>
<td>• Rocket propulsion</td>
<td>• Rocket propulsion</td>
</tr>
<tr>
<td>• Electricity + space power</td>
<td>• Electricity + space power</td>
<td>• Detection and remote sensing</td>
</tr>
<tr>
<td>• Potable water</td>
<td>• Potable water</td>
<td>• Radiotherapy</td>
</tr>
<tr>
<td>• Fissile fuel</td>
<td>• Potable water</td>
<td>• Radiation testing</td>
</tr>
<tr>
<td>• Transmuted waste</td>
<td>• Transmuted waste</td>
<td></td>
</tr>
<tr>
<td>• Tritium</td>
<td>• Destruction of chemical warfare agents</td>
<td></td>
</tr>
<tr>
<td>• Radioisotopes</td>
<td>• Radioisotopes</td>
<td></td>
</tr>
<tr>
<td>• Detection and remote sensing</td>
<td>• Detection and remote sensing</td>
<td></td>
</tr>
<tr>
<td>• Neutron radiography + tomography</td>
<td>• Radiography + tomography</td>
<td></td>
</tr>
<tr>
<td>• Radiotherapy</td>
<td>• Radiotherapy</td>
<td></td>
</tr>
<tr>
<td>• Neutron activation analyses/testing</td>
<td>• Proton activation</td>
<td></td>
</tr>
<tr>
<td>• Altered material properties</td>
<td>• Altered material properties</td>
<td></td>
</tr>
</tbody>
</table>

The US Department of Energy (DOE) funded a study within the Advanced Reactor Innovation and Evaluation Study (ARIES) project to assess other non-electric fusion applications to provide worthwhile new products, Waganer et al (9). A methodology, discussed in Appendix B, was developed to evaluate a wide range of products with a broad spectrum of attributes. The fusion products were evaluated and rank-ordered to determine which products would be recommended for future study (see Fig. 5). Table VI is a compilation of the fusion products that may be obtained from the various forms of energy derivable form fusion. For instance, hydrogen can be produced using electricity, neutrons, charged particles, and radiation. There are also unique products associated with each of the forms of fusion energy, and some alternate fusion confinement concepts would be better matched with certain products.

Use of D-T fuel, and to a lesser extent D-D fuel, would be best matched to the neutron-related products in the first column of Table VI. Intense, high-energy neutrons may be used in a multitude of applications to create or modify a wide range of useful, and perhaps unique, commercial and consumer products. Advanced fuels (such as D-3He, p-6Li, and p-11B) would be best suited for the charged particle applications shown in the second column. All fusing plasmas radiate a broad spectrum of radiation with a concentration in synchrotron radiation harmonics and X-rays. If the radiation products in the third column require a specific electromagnetic frequency, the plasma can be seeded with the appropriate impurity.

3.3 Discussion of the Results of the Evaluation of Fusion Applications

The relative attractiveness of the product with respect to the current US market is shown in Figure 5. These are weighted values derived using the approach characterized in Appendix B. Most of these applications are perceived as favorable and valuable. The production of hydrogen fuels, transmutation of nuclear wastes, and generation of electricity score slightly higher than the other applications. The remaining applications, with the exception of the fusion-fission breeder, have roughly similar scores.
3.4 Recommendations for the Large Fusion Plant Study

The decision analysis methodology indicates which applications are most favorable. Hydrogen production was the highest rated fusion power application. It produces an attractive product that will help convert the global hydrocarbon economy to a pure hydrogen economy. A fusion hydrogen-production facility would be considered a chemical plant, and as such, a very large plant would not be viewed unfavorably by the investors and the general public. The large size enables economy of scale effects to significantly lower the operating cost of electricity. We are reluctant, at present, to apply the economy of scale to electricity production alone. We do not want to increase the size of an electric power plant much larger than the 1300-1400 MWe scale of other systems. In addition, hydrogen would help extend petroleum resources and help reduce the production of greenhouse gases. The siting of the hydrogen production facility would only be limited by the hydrogen product distribution network.

The application of fusion power to the production of electricity has been investigated for over 50 years, so it need not be recommended for additional consideration. However, the results of this assessment would suggest electricity is a highly rated product except for its presently perceived economics. Transmutation of nuclear wastes and disposal of chemical wastes are highly rated. Other researchers are also continuing assessments of these products. Smaller fusion devices are
well suited for several of the other attractive products; several universities and small firms are investigating these applications.

Other applications, such as the burning of plutonium, power generation with existing fission products, and generation of radioactive isotopes remain as future candidates to be evaluated in more detail. The ARIES group is evaluating these applications to determine suitability for future study. A key recommendation of the study was to investigate the potential for fusion power to be coupled with large hydrogen production facility—the topic of this report.
4. Assessment of Electolytic Hydrogen Production from Fusion Power Plants for Energy Applications

4.1 Introduction

In this section, we assess the technical and economic potential for using fusion for hydrogen fuel production.

First, we examine how an electrolysis plant could be integrated with the fusion power plants discussed in the previous sections. Data on present and advanced electrolyzer technologies were used in the conceptual design of the electrolysis plant. Various types of electrolyzers were considered, including conventional alkaline electrolyzers which typically operate at 75-150°C, and high temperature electrolyzers which utilize high temperature heat in the range > 800°C—available from the fusion reactor—to provide part of the energy required for water splitting.

Second, we estimate the levelized cost of hydrogen produced from fusion-energy-powered electrolysis. Various types of electrolysis technology and scenarios for hydrogen production were considered. They include

1) Dedicated, 24 hour/day hydrogen production.
2) Hydrogen production only at off-peak times (night time) when electricity demand is low, with full electricity supply to the grid during peak hours.
3) Full hydrogen production at off-peak times and reduced production at on-peak times. In this mode, while the average cost of hydrogen is higher, it is possible to vary hydrogen production and load follow. Further, the incremental costs to the utility are reduced from the case in which the full electrical output will be transmitted to the grid.

The cost of hydrogen and electricity from fusion energy was compared to other long-term, zero-emissions energy systems, such as those based on renewables or decarbonized fossil fuels.

Third, because it can be used with high efficiency and zero emissions, hydrogen is attractive as a possible future transportation fuel. Once hydrogen is produced, it must be distributed to vehicles. We estimate the cost of distributing hydrogen from the production site to refueling stations. The delivered cost of hydrogen transportation fuel from fusion energy electrolysis is calculated for various cases.

4.1.1 Options for Producing Hydrogen from Nuclear Fission Power

In the 1960s and 1970s, with the promise of low cost nuclear power, the “nuclear hydrogen economy” was extensively studied. Options for nuclear hydrogen production included:

- Nuclear powered electrolysis of water;
- Thermochemical cycles for water splitting (using heat from nuclear plants);
- Thermal water splitting (using heat from nuclear plants); and
- Nuclear heat assisted fossil-to-hydrogen plants.
Several of these options have features that make them problematic for fusion powered hydrogen production.

- Thermal water splitting requires high temperatures ($T > 2000$ K) that are difficult to achieve with current fusion blanket designs and incur significant costs for materials.
- Thermochemical cycles have lower temperature requirements, but are still far from practicality because of materials constraints and short lifetime of conversion equipment (18).
- Nuclear power could provide heat input to hydrogen production from fossil fuels. For example, steam reforming of natural gas, which is an endothermic process, currently uses combustion of some natural gas to provide heat. However, the reductions in carbon emissions in displacing fossil heat sources with nuclear would be small, and the capital costs for heat exchangers would be large.

Therefore, in this study we have concentrated on variants of nuclear powered electrolysis, as the most promising fusion energy-to-hydrogen route.

### 4.2 Options for Fusion Energy Powered Electrolytic Hydrogen Production

#### 4.2.1 Options

To produce hydrogen, a fusion power plant supplies electricity to the electrolyzer. If high temperature electrolysis (HTE) is used, the fusion power plant supplies electricity plus heat. Hydrogen is compressed for storage and gas pipeline transmission to users (for example, for hydrogen fuel-cell vehicles). A schematic diagram of such a system is shown in Fig. 6.

![Schematic of Fusion Power Plant with Electrolyzer](image)

Fig. 6. Schematic of Fusion Power Plant with Electrolyzer.
The various types of fusion power plants, electrolyzers, and operating strategies that form the range of cases examined in this study are presented in Table VII. The choice of electrolyzer to produce the lowest cost hydrogen involves a trade-off between the capital cost payback and the electricity costs, which depends upon the efficiency of electrolysis. If electricity costs are high, this trade-off favors the exothermic mode. If electricity costs are low, conventional electrolysis is favored. Note that the exothermic and endothermic modes reduce the power plant thermal to electric efficiency by taking some of the process heat from the fusion plant to heat the electrolyzer.

Table VII. Design Options for Nuclear Fusion Powered Electrolysis

<table>
<thead>
<tr>
<th>Fusion Plant Options</th>
<th>1) ARIES-RS: 1 to 4 GW; conservative estimate of future fusion power plants</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2) ARIES-AT: 1 to 4 GW; more aggressive estimate</td>
</tr>
<tr>
<td>Electrolysis Options</td>
<td>1) High temperature electrolysis:</td>
</tr>
<tr>
<td></td>
<td>• Exothermic mode: capital cost $900/kW of hydrogen produced;</td>
</tr>
<tr>
<td></td>
<td>efficiency 111%</td>
</tr>
<tr>
<td></td>
<td>• Endothermic Mode: capital cost $1350/kW of hydrogen produced;</td>
</tr>
<tr>
<td></td>
<td>efficiency 136%</td>
</tr>
<tr>
<td>Operating Strategies</td>
<td>2) Conventional electrolysis:</td>
</tr>
<tr>
<td></td>
<td>• Capital cost $600/kW of hydrogen produced: efficiency 80%</td>
</tr>
<tr>
<td></td>
<td>• Capital cost $300/kW of hydrogen produced; efficiency 136%</td>
</tr>
<tr>
<td></td>
<td>1) Dedicated hydrogen production (all fusion electricity used to</td>
</tr>
<tr>
<td></td>
<td>produce hydrogen 24h/d)</td>
</tr>
<tr>
<td></td>
<td>2) Off-Peak hydrogen production: hydrogen production only during</td>
</tr>
<tr>
<td></td>
<td>off-peak electrical demand hours, when low-cost electricity is</td>
</tr>
<tr>
<td></td>
<td>available</td>
</tr>
<tr>
<td></td>
<td>3) Full Off-Peak: hydrogen production 24 h/d, but lower during on-</td>
</tr>
<tr>
<td></td>
<td>peak electrical demand times</td>
</tr>
</tbody>
</table>

4.2.2 Fusion Plant Assumptions

Two sets of performance and cost numbers were used for fusion plants. The first set is taken from the ARIES-RS designs (1). The second set of numbers is for an advanced fusion power plant design, the ARIES-AT (2). The estimated cost of electricity from these two designs, including the incremental utility costs, are shown in Table V.

For purposes of the cost model, it is assumed that the base COE for the ARIES-RS case scales as:

\[
\frac{COE}{COE_0} = \left( \frac{P}{P_0} \right)^{-0.35}
\]

where

COE is the cost of electricity at some reference plant size (Po).
The cost of electricity for the 2000, 3000 and 4000 MWe ARIES-AT fusion power plants is extrapolated from a preliminary 1000 MWe ARIES-AT design using the size scaling from a set of ARIES-RS plants in the power range. The base cost of electricity is

$$\frac{COE}{COE_0} = \left(\frac{P}{P_0}\right)^{-0.35}$$

Electricity costs are reduced in the ARIES-AT plants by improving thermal efficiency, reducing the cost of power plant components, and attaining a higher availability. These two sets of estimates from ARIES-RS and ARIES-AT are intended to “bracket” projections for future advanced fusion power plants.

As discussed in earlier sections of this report, there are added costs to the utility for large power plants (2 GW or larger), associated with spinning reserve and plant siting. The added costs are 0.35-0.60 cents/kWh depending on fusion generation costs.

Note that in all subsequent calculations of electricity and hydrogen costs, the incremental costs to the utility are included as part of the cost of fusion power.

### 4.2.3 Electrolyzer Assumptions

In water electrolysis, electricity is passed through a conducting aqueous electrolyte, dissociating water into its constituent elements hydrogen and oxygen via the reaction

$$2 \text{H}_2\text{O} \rightarrow 2 \text{H}_2 + \text{O}_2.$$  

Any source of electricity can be used, including intermittent or time-varying sources such as off-peak power, solar power, or wind power. The thermodynamics of water electrolysis is shown in Fig. 7. The energy input to split water is expressed in units of volts (which must be applied across the electrolysis cell), versus cell temperature. The total energy (ΔH) required to split water is:

$$\Delta H = \Delta F + T \Delta S$$

where:
- H = enthalpy
- F = free energy = electrical energy input
- T = temperature
- S = entropy

Below 100 C (where conventional alkaline and proton exchange membrane (PEM) electrolyzers operate), water is in a liquid state. As the temperature increases, the electricity requirement decreases (ΔF term), but the heat input requirement increases (T ΔS term). The voltage required for water splitting at constant temperature without heat exchange with the outside environment is called the “thermoneutral voltage.” For electrolyzers operating at less than 100 C, this voltage is about 1.48 volts. Above 100 C, it is about 1.3 volts. For electrolyzers operated at a voltage above the thermoneutral line, heat is released; the electrolyzer is exothermic. Below the thermoneutral line
The system is endothermic, and heat must be added to maintain the temperature. Also shown is the minimum voltage for water splitting, as a function of cell temperature. This voltage decreases with increasing temperature. In practical electrolyzers, there are electrical losses due to resistance in the electrolyte and electrodes and due to (1) “overvoltages” at the electrodes, which are required for electrochemical reactions and (2) heat losses to the environment. Thus the operating voltage is generally higher than the ideal values shown here.

The conversion efficiency of the electrolyzer

\[
\text{efficiency} = \frac{\text{HHV H}_2 \text{ out}}{\text{electricity in}}
\]

where

\[
\text{HHV is the higher heating value}
\]

is given as

\[
n = \frac{1.4811}{\text{Voltage}}
\]

Various types of electrolyzers currently in use are discussed in Appendix C.

Fig. 7. Thermodynamics of water electrolysis.
4.2.4 Other Alternatives for Fusion Powered Electrolysis

Instead of producing hydrogen centrally from fusion power, it would also be possible to produce hydrogen at refueling stations from low cost off-peak power (which might come from a central electric plant). Electrolysis technology is modular and well-suited to distributed production of hydrogen. In Sect. 6, we compare the delivered cost of hydrogen from centralized and decentralized hydrogen production.

4.3 Interfacing the Fusion Power Plant with the High Temperature Electrolyzer

In water electrolysis, DC electricity is input to electrolysis cells. If a conventional electrolyzer is used, there is no additional interface between the fusion plant and the electrolyzer. The electrolyzer has no impact on the design of the fusion power plant.

With high temperature electrolysis, some of the energy for water splitting is provided as process heat from the fusion power plant thermal conversion process stream. With 150°C water provided to the electrolyzer, a water/helium counterflow heat exchanger would be in the main, heat transport, helium loop downstream of the main turbine. This slightly degrades the thermal conversion system as less heat can be recovered in the recuperator. If the electrolyzer required water in the temperature range of 900°C, the heat exchanger would be located ahead of the helium turbine. This latter arrangement would significantly degrade the efficiency of the fusion plant thermal conversion system.

A conceptual design of ARIES-AT fusion power plants with heat recovery for high temperature electrolysis was developed as part of the ARIES program. The thermal conversion schematic for the 150°C water case is shown in Figure 8. The primary coolant for the fusion plant is a mixture of molten LiPb that extracts the heat from the power core. This LiPb coolant is heated to approximately 1150°C. The heat is transferred from the primary coolant to the secondary heat transfer media, helium, with a counterflow heat exchanger. A closed-cycle Brayton thermal conversion system is used to maximize the plant thermal conversion efficiency. With a maximum helium temperature of 1100°C, a three stage compression with intercooling, and a very efficient recuperator, the thermal conversion efficiency is estimated to be in the range of 60%. The high temperature electrolyzer will most likely require 150°C water; thus a helium-to-water heat exchanger would be downstream of the turbine. When the electrolyzer is in use, a portion of the helium mass flow out of the turbine outlet passes through the heat exchanger. When the electrolyzer is not in use (for example, during the daytime to satisfy the peak demands for grid electricity), the heat exchanger is by-passed.

We have chosen a high temperature electrolyzer, operated at 900°C in the exothermic mode. The input high-pressure water temperature is 150°C. At the electrolyzer, the high-pressure water is flashed to steam at the proper conditions. The amount of steam used is determined by the water consumption of the electrolyzer, which in turn depends on the fraction of the fusion power plant’s electrical output used for electrolysis and the hydrogen production rate.
Fig. 8. Details of fusion power plant electrical generation cycle with steam production for electrolysis.

The total fusion power converted to electricity and the efficiency of electrical conversion depend on the fraction of thermal power sent to the electrolyzer. To produce input steam for electrolysis, more heat is removed from the helium stream and it is not available for recovery in the recuperator. This means that more of the blanket energy must be used to heat the helium from a lower temperature, the overall cycle is less efficient, and the electricity production is less.

The impact of increasing the fraction of power going to high temperature electrolysis is shown in Figs. 9 and 10. Fig. 9 shows (for a nominal 3000 MWe fusion plant) the total fusion power production, the amount of power to the grid, and the amount of power to the electrolyzer, as a function of the fraction of total power used for electrolysis. When all the power goes directly to
the grid (no electrolysis), the plant output is 3152 MWe. When all the power goes to electrolysis, requiring significant heat for raising input steam (and less for the recuperator), the plant output is only 2869 MWe. The power output drops approximately linearly with the fraction that goes to electrolysis. As shown in Fig. 10, the electrical conversion efficiency drops from about 60.2% (when no power goes to high temperature electrolysis) to 54.8% (when all the power goes to electrolysis). Running the fusion power plant with high temperature electrolysis means that electrical production is less efficient and therefore more costly, as shown in Fig. 11 for ARIES-AT. (Note that this discussion only applies to high temperature electrolysis that requires process heat. Conventional electrolysis would not affect the power plant efficiency.)
4.4 Estimates of the Levelized Cost of Electricity and Hydrogen from Fusion Plants Compared to Other Long-Term Alternatives

Here we estimate the levelized cost of hydrogen produced from nuclear fusion powered electrolysis. As before, we consider various types of fusion plants, electrolysis technologies, and hydrogen production scenarios. The cost of hydrogen and electricity from nuclear fusion is compared to other long-term, zero- or near-zero-emissions energy systems, such as those based on renewable energies or decarbonized fossil fuels.

4.4.1 The Production Cost of Fusion Electricity

To derive the cost of fusion electricity, relative to plant size, we use fusion power plant cost and performance data from the ARIES studies; incremental costs as shown in Table V; and the variation of fusion power plant output with heat recovery for high-temperature electrolysis, shown in Figs. 9 and 10. Costs are determined for:

- ARIES-RS
- ARIES-AT
- ARIES-AT with heat recovery for high temperature electrolysis.

The results are shown in Fig. 12. The cost of power is somewhat higher if heat recovery is done for high temperature electrolysis because of the reduced fusion power output. The assumptions used in our calculations for estimating the cost of electricity and electrolytic hydrogen from fusion energy are summarized in Table VIII.
Table VIII. Cost and Performance Assumptions for Calculations of Hydrogen Production Costs

<table>
<thead>
<tr>
<th>Electrolysis type</th>
<th>High Temperature Electrolysis</th>
<th>Conventional Electrolysis: Near Term</th>
<th>Conventional Electrolysis: Long Term</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electrolyzer capital cost ($/kW H₂ out)</td>
<td>900</td>
<td>600</td>
<td>300</td>
</tr>
<tr>
<td>Efficiency %</td>
<td>111</td>
<td>80</td>
<td>80</td>
</tr>
<tr>
<td>Electrolyzer O&amp;M fraction of total capital cost ($/year)</td>
<td>0.03</td>
<td>0.03</td>
<td>0.03</td>
</tr>
<tr>
<td>Capacity factor</td>
<td>85</td>
<td>85</td>
<td>85</td>
</tr>
<tr>
<td>Electrolysis plant life (years)</td>
<td>20</td>
<td>20</td>
<td>20</td>
</tr>
</tbody>
</table>

Fusion plant type

<table>
<thead>
<tr>
<th></th>
<th>ARIES-RS</th>
<th>ARIES-AT</th>
<th>ARIES-AT with process heat recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fusion plant availability factor</td>
<td>0.76</td>
<td>0.85</td>
<td>0.85</td>
</tr>
<tr>
<td>Fusion plant life (yr)</td>
<td>40</td>
<td>40</td>
<td>40</td>
</tr>
</tbody>
</table>
Other assumptions used to estimate the cost of electricity and electrolytic hydrogen from fusion energy include:

- Fusion Plant size = 1000-4000 MW
- \( f \) = fraction of off-peak power to electrolysis \( 0 - 1.0 \)
- \( P_{on} \) = on-peak power cost = 5-8 cents/kWh
- \( h_{on} \) = # on-peak hours = 8-16 hours
- Real discount rate = 7.75%
- Capital Recovery Factor (\( N=20 \) yrs) = 0.1

### 4.4.2 Cost of Dedicated Hydrogen Production

In this scenario, the fusion plant is dedicated solely to the production of hydrogen. The analysis procedure is given in Appendix D. A 3000 MW fusion power plant dedicated to hydrogen production would make enough hydrogen fuel for 6-8 million hydrogen fuel cell cars (about the number of cars in the Los Angeles Basin today).

**3000 MW fusion power plant capital cost range: $5.7-$8.7 billion**

**EXOTHERMIC OPERATION; Total Cost = $2637 - $3589/kWh²**

**ENDOTHERMIC OPERATION; Total Cost = $2960-$3820/kWh²**

![Diagram of fusion power plant and electrolyzer](image)

**Fig. 13.** Comparison of dedicated, fusion-powered electrolytic hydrogen production by exothermic and endothermic operations shows that exothermic operation is less costly.
Figure 13 compares the cost of producing hydrogen from an exothermic reaction (heat supplied at 150°C) that is achieved with a less expensive, less efficient electrolyzer to the cost of producing hydrogen from an endothermic reaction (heat supplied at 900°C) achieved with the higher efficiency and higher cost electrolyzer. In both cases electrolyzers are coupled with a 3 GW fusion plant, and the comparison accounts for related effects on fusion plant performance. It was found that the exothermic case is approximately 12% less costly on the basis of combined capital cost to produce a given quantity of hydrogen. The range of the cost results arises from the range of performance and cost of the fusion plants assumed.

Figure 14 presents the basis for the trade study between exothermic HTE and conventional electrolyzer. Again, the efficiency and cost of the electrolyzers are compared along with the required changes in the fusion plant. (Cost results are displayed separately in Fig. 15.)

The levelized cost of dedicated hydrogen production is shown in Fig. 14 for ARIES-RS and ARIES-AT fusion plant designs with high temperature electrolyzers (costing $600/kW H2 out), and conventional electrolyzers (costing $300 or $600/kW H2 out). The data indicates that the cost of hydrogen is strongly driven by the cost of the fusion plant—the use of ARIES-AT results in a much lower hydrogen cost. For each type of plant the cost of hydrogen production decreases with increasing plant size.

![Fig. 14. Comparison of fusion-powered H2 production using high-temperature electrolysis vs. conventional electrolysis.](image-url)
For both types of plants, the lowest hydrogen cost is obtained using high temperature electrolysis. If conventional electrolyzers could be produced for $300/kW H_2 out, hydrogen costs would be close to those for high temperature electrolysis. In this circumstance, one might choose the conventional system to minimize technical risk.

As seen in Fig. 15, hydrogen costs with dedicated plants are in the range $18-32/GJ for ARIES-RS fusion plants, and $13-21/GJ for ARIES-AT designs. These costs are significantly higher than for hydrogen derived from biomass or decarbonized fossil fuels (which are in the range $8-10/GJ). Solar or wind electrolytic hydrogen is expected to cost $15-25/GJ, which is in the same range as the fusion hydrogen. However, wind or solar plants could be used at much smaller scale than fusion plants. We conclude that dedicated hydrogen production is probably too costly to compete with other low- or zero-CO_2 hydrogen options, given current data and assumptions.

4.4.3 Economics of Electrolytic Hydrogen Production from Off-Peak Fusion Power

Another operating strategy is to produce hydrogen during off-peak electric demand hours, when the value of electricity is low. A schematic of a plant configured to produce hydrogen at off-peak hours is shown in Fig. 16.

It is assumed that the plant sells on-peak power for 5-8 cents/kWh (the range projected for future low- or zero-CO_2 generation options). The related price for off-peak power, assuming for example an average price of 4.5 cents/kWh, would range respectively from 1-4 cents/kWh. During the off-peak hours, the plant sells low cost electricity to an electrolysis plant. (If high temperature electrolysis is used, the fusion plant also provides heat to the electrolyzer.) The cost of hydrogen is then estimated based on this off-peak power cost.
DAYTIME OPERATION (on-peak)

\[ \text{Electricity to electrolysis} = f \times P \]

NIGHTTIME OPERATION (off-peak)

\[ \text{Electricity to grid} = (1-f) \times P \]
\[ \text{Electricity to electrolysis} = f \times P \]
\[ \text{Eff. of Electrolyzer} = n \]
\[ \text{Hydrogen output} = n \times f \times P \]

Fig. 16. Fusion-powered electrolysis to produce H2 at off-peak hours.

In Figs. 17 and 18, the cost of off-peak fusion hydrogen is shown as a function of fusion plant size for ARIES-RS and ARIES-AT cases, respectively. It is assumed that half of the off-peak fusion power goes to electrolysis \((f=0.5)\), and the on-peak power cost is 6 cents/kWh i.e., for 4 cents/kWh average COE the off peak COE is 2 cents/kWh. Conventional electrolysis at $300/kWh H2 out gives the lowest hydrogen cost. (High temperature electrolysis has a higher capital cost, so that the lower capital utilization of off-peak production yields a higher hydrogen cost.) There are strong scale economies for hydrogen costs.

Fig. 17. Cost of H2 from off-peak fusion power: ARIES-RS (on-peak power = 6 cents/kWh)
For large ARIES-AT plants (3000-4000 MWe), the cost of hydrogen is about $8-15/GJ. For ARIES-RS plants, subject to the condition that the average COE is less than the peak COE, only the 4000 MWe plant produces electricity for less than 6 cents/kWh, and the cost of hydrogen is in the range $20-25/GJ.

Figures 19-22 show that hydrogen cost depends on plant size and on-peak power cost for ARIES-RS and ARIES-AT with various electrolysis technologies. The hydrogen cost is quite sensitive to the on-peak power cost. If on-peak power is valuable (≥7 cents/kWh), the fusion power plant can afford to sell the power to the electrolyzer at low or zero cost, yielding a low hydrogen cost and still maintaining a good rate of return. For the best case (ARIES-AT, with a low cost electrolyzer, and on-peak power cost of 8 cents/kWh) hydrogen costs less than $5/GJ. A minimum off-peak power price of zero is imposed, even though the fusion plant could afford to pay the electrolyzer plant to take its off-peak power and still maintain the desired rate of return.

Fig. 18. Cost of H2 from off-peak fusion power: ARIES-AT (on-peak power = 6 cents/kWh)

Fig. 19. Cost of hydrogen from off-peak fusion power, conventional electrolyzer, $600/kWh2, ARIES-RS
Fig. 20. Cost of hydrogen from off-peak fusion power, conventional electrolyzer, $300/kWh2, ARIES-RS

Fig. 21. Cost of hydrogen from off-peak fusion power, conventional electrolyzer, $600/kWh2, ARIES-AT

Fig. 22. Cost of hydrogen from off-peak fusion power, conventional electrolyzer, $300/kWh2, ARIES-AT
4.4.4 Economics of Electrolytic Hydrogen Production Using Both Off-peak and On-peak Power

As an example of this mode of operation, we consider the case of an ARIES-AT, 4000 MWe fusion plant coupled to a 4000 MWe input conventional electrolyzer system. The system operates to produce the full amount of hydrogen off-peak (assumed to be half the time), and the rest of the time at 1,000 MWe input to the electrolyzer. Because the plant does not commit more than 3000 MWe to the grid, the incremental costs are lower and drop to 3.7 mills/kWh, for a total COE of 51 mills/kWh for the ARIES-RS. Incremental costs and total COE are 3.3 mills/kWh and 35 mills/kWh, respectively, for the ARIES-AT.

During off-peak periods, it is economic to produce hydrogen. Provided that most of the hydrogen is produced off-peak, it remains economic to produce some hydrogen during on-peak periods. This flexible approach allows a continuing trade-off between hydrogen production and electricity sales in the range of 1000 to 3000 MWe, and the system should therefore be able to load follow.

The cost of hydrogen production for the $300/kW H$_2$ out conventional electrolyzer will be about $10.3/GJ for the ARIES-AT case. A use of 2000 MWe of conventional electrolyzer plus 1000 MWe of high temperature electrolyzer operating all of the time yields a similar cost of hydrogen. A range of cases is shown in Fig. 23. The equivalent configuration is shown schematically in Fig. 24.

Fig. 23. Cost of producing hydrogen by various operating strategies, ARIES-AT, on-peak power at 6 cents/kWh, conventional electrolyzer $300/kWH2.
4.4.5 When Is Electrolytic Hydrogen from Fusion Energy Competitive with Other Sources of Hydrogen?

The cost of hydrogen from fusion power is compared to the cost of other hydrogen production methods in Fig. 25. Hydrogen production cost is plotted against hydrogen output in million standard cubic feet per day. Steam reforming of methane is shown for two natural gas prices ($3 and $6/MBTU). A case with sequestration of CO$_2$ is also shown. Hydrogen from gasification of
biomass and coal are plotted as well. Finally, a variety of fusion hydrogen options are shown for dedicated and off-peak power hydrogen production from ARIES-RS and ARIES-AT plants. (In these cases on-peak power is valued at 7 cents/kWh).

The primary future competition for fusion electrolysis produced hydrogen appears to be hydrogen from biomass and fossil fuels (notably natural gas and coal). The fusion option will be particularly important in those geographic areas that are not well endowed with these other energy sources.

As noted above, hydrogen from a dedicated fusion power plant is generally more costly than other alternatives. However, hydrogen from off-peak power is competitive with other low carbon sources (e.g. H₂ costs $8-10/GJ) if all the following conditions are met:

- Large fusion power plant size (3000 MW or larger because of scale economies in capital cost)
- Low cost fusion power plant designs, with high availability are developed such as ARIES-AT ($1800/kW or less, 85% capacity factor).
- Low cost conventional electrolyzers are used ($300/kW H₂ out)
- On-peak power has a value of at least 6 cents/kWh. This allows revenue from on-peak operation to “support” a low off-peak price for power to the electrolyzer.
- Low discount rate. Capital intensive technologies such as nuclear power fare better if the discount rate is relatively low. In these cases, we assumed a discount rate of 7.75%, which gives a capital recovery factor of about 10%. With a higher discount rate (say 10% or higher), it is significantly harder for nuclear fusion to compete with thermochemical hydrogen production, where capital costs are a lower fraction of the total hydrogen cost.

It may be possible for hydrogen from off-peak nuclear power to compete with other low- or zero-CO₂ large hydrogen production options, but stringent cost and performance goals must be met, and on-peak power must be valuable.

Here we estimate the delivered cost of hydrogen transportation fuel that is produced centrally from off-peak nuclear fusion power.

Our base case is shown in Fig. 26. Here, a 3000 MW nuclear fusion plant produces electricity to match a utility demand profile and produces hydrogen for fuel cell vehicles. In the daytime the plant produces electricity only. At night, half the power goes to hydrogen production and half to the electric grid. A conventional electrolyzer is used. Hydrogen is compressed to 1000 psi and stored at the electrolysis plant. Storage capacity of one day’s hydrogen production is installed. A pipeline system is connected to a series of hydrogen refueling stations. Table IX gives the component sizes and costs of such a system.

<table>
<thead>
<tr>
<th>Factor/Facility</th>
<th>Cost</th>
<th>Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Centralized hydrogen production:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>electrolyzer</td>
<td>$720 million</td>
<td>Conventional electrolyzer; $600/kWh2out</td>
</tr>
<tr>
<td>Centralized hydrogen compression</td>
<td>$45 million</td>
<td>60 MWe x $750/kWe</td>
</tr>
<tr>
<td>Central hydrogen storage</td>
<td>$150 million</td>
<td>150 million scf; $1/scf</td>
</tr>
<tr>
<td>Hydrogen distribution network</td>
<td>$380 million</td>
<td>15, 40-km pipeline segments = 600 km @ $0.625 million/km</td>
</tr>
<tr>
<td>Refueling stations</td>
<td>$105 million</td>
<td>150 stations, 1-million scf H2/day capacity; serving 654 cars/day; $0.7 million per station</td>
</tr>
<tr>
<td>TOTAL (excluding electrolyzer)</td>
<td>$680 million</td>
<td>--</td>
</tr>
<tr>
<td>TOTAL (including electrolyzer)</td>
<td>$1,400 million</td>
<td>--</td>
</tr>
</tbody>
</table>

It is important to note that the system described above would serve about 1.3 million hydrogen fuel cell cars, representing about 20% of the cars in the Los Angeles Basin today. Fusion derived central hydrogen production would not be attractive until a large demand for hydrogen vehicle fuel had already been developed using other sources of hydrogen.

The delivered cost of fusion-derived H2 transportation fuel is given for various cases in Fig. 27. For the fusion cases, we assume that low-cost, $300/kWh2out, conventional electrolyzers are used for off-peak power production. For the ARIES-RS 3 GWe case, the production cost of H2 is $12/GJ and the delivered cost of fuel is about $20/GJ. For the ARIES-AT 3 GWe case, the production cost
Fig. 26. Schematic of nuclear fusion co-production of electricity and hydrogen with H2 pipeline delivery to gaseous H2 refueling stations.
Delivered Cost of Hydrogen Transportation Fuel ($/GJ)

Fig. 27. Delivered cost of hydrogen transportation fuel ($/GJ).

of H₂ is $7/GJ and the delivered cost is about $15/GJ. (It is assumed here that the on-peak power cost is 7 cents/kWh.)

For fusion derived H₂ the delivered H₂ cost is comparable to that for H₂ from onsite (small scale, distributed) electrolysis using off-peak power costing 1-3 cents/kWh. The cost of H₂ from steam reforming of natural gas is given for two values of natural gas feedstock price ($3-6/GJ). The added cost for CO₂ sequestration is about $1/GJ. Total delivered costs for H₂ from natural gas are $12-16/GJ. H₂ from biomass costs $15/GJ delivered.
If optimistic cost and performance projections (ARIES-AT) are used for fusion plants and electrolyzers, the cost of hydrogen from off-peak power could become competitive with other sources of low CO₂ hydrogen. With ARIES-RS projected costs, the cost of off-peak fusion hydrogen is higher than those for H₂ from decarbonized fossil or biomass sources. This calculation supports the importance of reducing fusion plant capital costs, if off-peak hydrogen production is to become competitive.
6. Conclusions on Co-production of Electricity and Hydrogen

We have examined the prospects for producing hydrogen transportation fuel from nuclear fusion power. Based on projections for advanced fusion power plants and electrolyzers, and data on the cost of developing hydrogen infrastructure, we estimate the cost of hydrogen production and delivery to vehicles. Various types of fusion plants (ARIES-RS and ARIES-AT), electrolysis technologies (high temperature and conventional), and scenarios for hydrogen production are considered [hydrogen production only at off-peak times (nighttime) when electricity demand is low, with electricity production during peak hours; and dedicated (24 hour/day) hydrogen production].

Our results are summarized below:

1) Hydrogen costs from dedicated facilities are in the range $18-32/GJ for ARIES-RS fusion plants, and $13-21/GJ for ARIES-AT designs. The lowest prices occur at the largest fusion plants. High temperature electrolysis yields the lowest hydrogen cost for dedicated fusion/electrolysis plants. Dedicated fusion hydrogen costs are significantly higher than those for hydrogen derived from biomass or decarbonized fossil fuels (which are in the range $8-10/GJ). Solar or wind electrolytic hydrogen cost $15-25/GJ, which is in the same range as the fusion hydrogen. However, wind or solar plants could be used at much smaller scale than fusion plants. We conclude that dedicated hydrogen production from fusion plants is likely to be too costly to compete with other low- or zero-CO$_2$ hydrogen options.

2) Hydrogen from off-peak nuclear power can be competitive with other low carbon hydrogen sources (e.g., H$_2$ costs $8-10/GJ) if all the following conditions are met simultaneously:

- Large fusion power plant size (3000 MW or larger because of scale economies in capital cost)
- Low cost fusion power plant designs, with high availability are developed such as ARIES-AT ($1800/kW or less, 85% capacity factor).
- Low cost conventional electrolyzers are used ($300/kW H$_2$out)
- On-peak power has a value of at least 6 cents/kWh. This allows revenue from on-peak operation to “support” a low off-peak price for power to the electrolyzer, yielding a competitive hydrogen cost.
- Low discount rate. Capital intensive technologies such as nuclear power fare better if the discount rate is relatively low. In these cases, we assumed a discount rate of 7.75%, which gives a capital recovery factor of about 10%. With a higher discount rate (say 10% or higher), it is significantly harder for nuclear fusion (even under the most optimistic assumptions) to compete with thermochemical hydrogen production methods, where capital costs are a lower fraction of the total hydrogen cost.

3) The lowest cost option for hydrogen production from off-peak nuclear fusion power is conventional or PEM electrolysis costing $300/kW H$_2$out, which is within projections for this technology. High temperature electrolysis is more efficient, but is also more costly, because the electrolyzer is expensive and is only utilized during off-peak hours. This suggests that heat
recovery from the nuclear plant is not necessary for off-peak hydrogen production. Thus, there may be little reason to site the electrolyzer at the nuclear plant. There will be trade-off between the cost of transmitting hydrogen to a refueling station versus the cost of transmitting electricity to a small electrolyzer at a refueling station. Decentralized hydrogen production may be preferable to centralized, depending on the location. For example, if the electricity grid is already built and electric transmission is low cost, but the hydrogen system is not, decentralized production may be preferred.

4) The option to produce some hydrogen at on-peak times is interesting because it may allow the large fusion system to electrically load follow, albeit at slightly higher hydrogen cost, for the nominal on-peak electricity price.

There are a number of long term, low CO₂ sources of hydrogen for future fuel needs. These include decarbonized fossil fuels, biomass, solar, wind, and nuclear. The best choice will be determined by the available primary resources and the type of demand, and by progress in hydrogen production technologies.
7. Acknowledgements

The authors appreciate the interest and support of William Dove of the Office of Fusion Energy Sciences of the Department of Energy, the valuable input from Ronald Miller of the University of California at San Diego, and useful comments from Stanley Milora of the Oak Ridge National Laboratory.
8. References


Appendix A. Definitions

Ancillary Services- Interconnected Operations Services identified by the US FERC, Orders 888 and 2000 (A1) as necessary to effect a transfer of electricity between purchasing and selling entities and which a transmission provider must include in an open access transmission tariff.

Energy Imbalance Service - Provides energy correction for any hourly mismatch between a transmission customer’s energy supply and the demand served.

Operating Reserve:

Spinning Reserve Service - Provides additional capacity from electricity generators that are on line, loaded to less than their maximum output, and available to serve customer demand immediately should a contingency occur.

Supplemental Reserve Service - Provides additional capacity from electricity generators that can be used to respond to a contingency within a short period, usually ten minutes.

Reactive Supply and Voltage Control - Provides reactive supply through changes to generator reactive output to maintain transmission line voltage and facilitate electricity transfers.

Regulation and Frequency Response Service - Provides for following the moment-to-moment variations in the demand and supply in a control area and maintaining scheduled interconnection frequency.

Scheduling, System Control and Dispatch Service - Provides for scheduling, confirming and implementing interchange schedule with other Control areas and ensuring operational security during the interchange transaction.

Area Control Error- The instantaneous difference between actual and scheduled interchange, taking into account the effects of frequency bias

Load Following - Process of regulating generation to follow changes in customer demand

Loss of Load Expectation (LOLE)- The expected number of days in the year when the peak demand exceeds the available generating capacity, calculated on an hourly basis and summed for the year. The index is referred to as Hourly Loss of Load Expectation if hourly demands are used to calculate reliability.

Adequate Regulating Margin- Minimum on-line capacity that can be increased or decreased to allow the electric system to respond to all reasonable instantaneous demand changes to be in compliance with the Control Performance criteria.

Available Capacity Margin- The difference between Available Resources and Net Internal Demand expressed as a percent of Available Resources. It is the capacity available to cover random factors such as forced outages of generating equipment, demand forecast error, weather extreme, and capacity service schedule slippage.

Operating Reserve Sharing - Additional capacity either from generators that are on line, loaded to less than their maximum output, and available to serve demand immediately due to contingency or generators that can respond in ten minutes of contingency occurrence. Interconnections allow the sharing of operating reserves between Control Areas, which reduces the amount of operating reserves each Control Area must carry individually.
Reliability (Adequacy) - The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
Appendix B. Prior Studies

B.1. Survey of Prior Studies

To determine which applications could best be accomplished with fusion, the entire range of alternative product applications was examined. There have been prior studies that surveyed the opportunities for fusion to provide a range of applications and products. An EPRI-sponsored review (B1) of the status and options for fusion in 1977 provided the starting point. The General Atomics FAME Study (B2) examined the technical processes and economics of many alternate fusion applications. A more recent assessment of near-term commercial opportunities from long-range fusion research was incorporated in our database (B3). Specific data on various applications by their advocates have contributed to the understanding of the concepts, products, and the intended markets and marketing strategy.

The products identified include process heat, electricity, hydrogen fuels (and synthetic fuels), desalination, waste processing, ore reduction, transmutation of elements, detection/remote sensing, and space propulsion. Some of these product applications are unique to fusion, while others must economically compete with existing energy technologies. Some of the applications are independent of fusion confinement concepts. Others may effectively use a smaller fusion device or a confinement concept previously judged not suitable for electrical power generation.

B.2. Assessment Methodology

The key step in the assessment is the formulation of an appropriate decision analysis methodology to evaluate the potential fusion products identified in Table VI. The goal is to assess the ability of a fusion power source to provide a needed and useful product to the customer at a reasonable cost. The customer might be a consumer, company, university, laboratory, or government agency. To address the technical capability and competitiveness of a particular neutron source application, several questions must be addressed in a documented process:

- What is the market potential for the application?
- What is the cost of the product?
- Is the product cost competitive with other existing and proposed applications?
- Is the time to market consistent with the market demand?
- Are there critical, difficult, or costly developments required?
- Are there any significant environmental, safety, and licensing issues?

To address these general questions, a decision analysis methodology was formulated to assess and prioritize the market potential of the fusion products identified earlier. The major elements of this decision analysis methodology are show in Figure B-1.
First, all the potential applications for fusion were surveyed and cataloged for this evaluation. Next, a decision analysis methodology was developed to evaluate the very dissimilar product applications. This decision analysis methodology was validated with prior large, high technology programs that have succeeded, failed, or were canceled.

The initial step of the decision analysis methodology identified the critical attributes for a successful product that meets the perceived expectations of the customer and/or decision-maker (performance, schedule, cost, or safety). These attributes were selected to characterize the candidate application and help guide the decision-maker as to the benefits and risks in deciding to undertake (support) the project.

Some of the attributes could be measured directly, such as product economics and schedule, while others are indirect or subjective values, such as good will, strategic advantage, and environmental impact. Table B-1 lists the general categories as determined from the examination of past large, high technology projects and the attributes adopted for this assessment. Weighting values were assigned to each of the attributes according to the perceived importance to the decision-makers. Some of the long-term market trends suggested in the December 1997 Kyoto Climate Change Conference were incorporated into the weighting scheme. These weighting values are adjustable to allow sensitivity studies and examination of changing priorities.

Fig. B-1. Assessment process task flow.
History has provided several examples of large projects that attempted to commercialize innovative, high technology products, see Table B.2. Some have succeeded; others have failed. But we can learn from both results. By examining these projects and their outcomes, a set of attributes was developed to characterize those future products that might have a higher likelihood of success. These data were used to validate the methodology process.

Table B.1 Decision Criteria Attributes

<table>
<thead>
<tr>
<th>Market Factors</th>
<th>Relative Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Necessity</td>
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</tr>
<tr>
<td>Uniqueness</td>
<td>High (3)</td>
</tr>
<tr>
<td>Market Potential</td>
<td>High (3)</td>
</tr>
<tr>
<td>Environmental Factors</td>
<td></td>
</tr>
<tr>
<td>Depletion of Valued Resources</td>
<td>High (3)</td>
</tr>
<tr>
<td>Environmental Impact</td>
<td>High (3)</td>
</tr>
<tr>
<td>Economic Factors</td>
<td></td>
</tr>
<tr>
<td>Competitive Product</td>
<td>Moderate (2)</td>
</tr>
<tr>
<td>Improvement in GNP</td>
<td>Low (1)</td>
</tr>
<tr>
<td>Risk Factors</td>
<td></td>
</tr>
<tr>
<td>Investment for Return of Capital</td>
<td>Moderate (2)</td>
</tr>
<tr>
<td>Maturity of Technology</td>
<td>Moderate (2)</td>
</tr>
<tr>
<td>Time to Market</td>
<td>Moderate (2)</td>
</tr>
<tr>
<td>Public Perception Factors</td>
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<tr>
<td>National/Company Prestige</td>
<td>High (3)</td>
</tr>
<tr>
<td>Public/Governmental Support</td>
<td>High (3)</td>
</tr>
</tbody>
</table>

Table B.2 Large National and International Projects Assessed

- US Supersonic Transport
- Superconducting Super Collider
- Jumbo Jet (Super 747 Category)
- High Definition TV (Analog and Digital)
- Manned Moon and Mars Landing

The projects in Table B.2 were examined to determine the customers’ expectations, if expectations were met, and if the project was successful in commercializing the product. Key features, benefits, and risks in each of these projects were identified and examined. From that examination, a set of attributes was selected to characterize the potential project and help guide the decision maker as to the benefits and risk in deciding to undertake (support) the project.

The identification and ranking of these attributes may appear to be rather discretionary and judgmental, but much of the information is in the public record and literature. Even if the specific
values are subject to interpretation, the observed trends can be of value. After all, past data are being used to predict the future acceptance of an evolving product.

The attributes are grouped into similar factors. Market factors help determine how well the product can penetrate the proposed market (necessity for the product and the market potential) and the uniqueness of the product. Environmental factors examine how well the product will help preserve or restore the natural resources and the level of environmental impact (positive or negative). Economically, can the new product compete on a competitive basis and will it significantly improve the US Gross National Product? Risk is assessed with regard to return on capital, maturity of the technology, and time to market. The public perception is measured in terms of perceived prestige arising from the product and public or governmental support.

After the attributes and weights are established, an additive utility theory methodology is used to qualitatively evaluate the proposed applications in terms of their market potential, environmental considerations, economic impact, risk, and public perception. Both multiplicative and additive utility functions \( (B4) \) were considered for the decision methodology. The multiplicative utility function was considered to be inappropriate in this assessment because a score of zero in any single attribute would disqualify the product from further consideration. This might be appropriate when all the concepts under consideration are well developed. In that case, a concept should be disqualified if it has a fatal flaw or cannot achieve a mandatory threshold value. But at this stage in the definition of the fusion products, a score of zero should not eliminate a product from consideration, as it might be capable of improving that particular attribute in the future. The adopted additive utility function will penalize the product with a zero score for that evaluation factor, but not eliminate it from further consideration. The formulation of the decision analysis methodology is:

\[
\text{Score} = \Sigma \text{ (Attribute Weight)} \times \text{ (Attribute Value)}
\]

\[
\text{Attribute Weights} = 1 \text{ to } 3
\]

\[
\text{Attribute Values} = -5 \text{ (least attractive)} \text{ to } +5 \text{ (most attractive)}
\]

The weighting scale is simple: 1 for less important factors and up to 3 for factors deemed to be very important. The attribute values for each product were established on a scale of -5 (for a very negative attribute) to +5 (for a very attractive attribute). The use of positive and negative attribute values is arbitrary in this assessment, but this positive and negative value approach helps an evaluator more easily judge positive and negative attributes. Each of the attributes was assigned a qualitative description of the least attractive, neutrally attractive, and most attractive attributes to help reduce the bias of the evaluator. This methodology was tested with prior projects and produced results that correlated well with historical data.

B.3. Application of Decision Analysis Methodology

Most of the candidate fusion products in Table VI. were selected for assessment. The intent was to evaluate a complete range of viable fusion products. The processes to alter material properties and the dissociation of water were not selected because they are not presently well developed and the market potential is judged to be insufficient to justify inclusion in the study.
The choice of a fusion confinement concept is immaterial in assessing many of the attributes of the product, especially the market factors, the public perception factors, and many of the environmental factors. But when the risk factors of investment, technology maturity, and time to market are considered, a confinement concept must be mated with the product to complete the assessment.

Table B.3 illustrates the selected fusion neutron products identified in the first column. The first row lists the attributes that are addressed for each product. The associated attribute weighting factors are shown in the second row. The individual attribute values for each product are shown in the corresponding column. The highest and lowest scores for each attribute are identified by green or yellow cells (or dark or light grey), respectively, to highlight best or worst attribute scores.

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After completion of this evaluation process, it was reviewed by a small assessment group from the ARIES team and then by the entire ARIES project team and some fusion experts from the University of Wisconsin Fusion Technology Institute. Meanwhile, several product advocates critiqued the methodology and assessment. Comments from all of these sources were integrated into the preliminary assessment data shown in Table B.3. The weighted sum scores for each product are shown on the last column of the table. A rank-ordered graph of these scores is shown and discussed in the next section.

To understand why these products are evaluated as such, one has to examine the attributes of the chosen products and weighting methodology used. Only one of the products was rated at the maximum positive value of +5 for a single attribute, and none were scored at the maximum negative value. Most individual scores were in the middle of the range. The maximum weighting sum for any product was only 40% of the highest possible score.

The products that scored well in the weighted sums had several individual attributes that scored relatively high. These products were generally perceived to have shorter development times, more mature technologies, and good public support. They also required less investment capital to reach the market. Conversely, the breeder application was rated as the least attractive and was not viewed as being currently needed in the U.S. marketplace—a large investment would be required, a long time to market is foreseen, and an immature technology is assumed. As an aid, the high score for each attribute is shaded in Table B.3.

The production of hydrogen scored well because it captured the highest scores in 7 of the 12 attributes. It is judged a highly necessary product, with significant market potential. It helps to prolong critical petroleum resources while greatly improving the environment by not releasing any CO$_2$ when used. Since it will likely become a major industry, it will improve the U.S. Gross National Product. Because it substantially helps conserve resources and improve the global environment, it will generate a lot of public support and prestige. On the negative side, it is not viewed as being overly competitive at present, will require a lot of investment capital, needs to be technically developed, and would require a significant time to market the product. Nevertheless, the larger positives outweigh the negatives, making hydrogen (or synthetic fuel) production the highest scoring fusion product. The production of hydrogen with fusion has been proposed using several different processes.

The transmutation of nuclear wastes rated closely as the second choice. Transmutation of nuclear wastes would likely be accomplished in a compact device with excellent confinement. The nuclear wastes probably would be in containers, housed in the reactor, exposed to the neutrons for long periods of time. This is a rather fusion-unique product with significant market potential, especially with appeal to cleaning up the nuclear waste and not despoiling the environment. The neutral attributes are helping with resources, competitive nuclear disposal costs compared with other disposal options, helping the GNP, prestige, and public support. The scores of some of these attributes could be increased, but it might entail a risk to highly publicize those attributes. The negative aspects are only slightly negative. Because it is viewed as a compact device, it does not require a huge capital investment. It has a reasonable technical maturity and it will require a nominal time to market. The high marks for this product coupled with moderate negative scores yield a highly rated product.
A large, central station, electric generating plant also scored quite well. Interestingly, it did not have any of the highest rated attributes, but it did score well in many categories and only had a few negative scores. As such, it has a very good overall, weighted score.

The remaining fusion products had few high attribute scores to elevate their position. Because they are generally related to smaller fusion devices, they did not have many large negative scores like large capital investment or financial risk. They all scored well above the neutral or zero score. Thus, they all should be retained for further examination and concept improvement.

The fusion-fission breeder has many negative attributes. The market for fission fuel is depressed at this time; hence, the necessity for the product is not positive and the market potential is low. The concept would be a large plant, requiring significant capital investment, with a long time to market. The few small benefits for this concept presently do not outweigh the larger, negative aspects of the fusion-fission breeder concept.
Appendix C. Electrolyzers

Various types of electrolyzers are in use, Figure C-1. Commercially available systems today are based on alkaline technology. Proton exchange membrane (PEM) electrolyzers have been demonstrated, are in the process of being commercialized, and hold the promise of low cost. PEM electrolyzers also have advantages of quick start-up and shutdown and the ability to handle transients well. Experimental designs for electrolyzers have been developed using solid oxide electrolytes and operating at temperatures of 700°C to 900°C. High temperature electrolysis systems offer higher efficiency of converting electricity to hydrogen, as some of the work to split water is done by heat, but materials requirements are more severe.

Operating voltages and current densities are shown for various types of electrolyzers in Figure C-2. We see that conventional electrolyzers operate at fairly high voltages and low current densities as compared to PEM (or SPE) electrolyzers or high temperature electrolysis. The voltage for high temperature electrolysis is theoretically about 1.1-1.3 volts.

Conventional alkaline electrolyzers are typically about 70-85% efficient on a higher heating value basis [efficiency = hydrogen out (HHV)/electricity in]. PEM electrolyzers have efficiency of about 80-90%. High temperature electrolysis could have an electrical efficiency of over 100%, although heat would have to be provided to the cell as well.

Water electrolysis can be used to produce hydrogen over a wide range of scales ranging from a few kilowatts to hundreds of megawatts. Capital costs for electrolyzers have been estimated by various authors (C1, C2, C3, C4). The capital cost of alkaline systems varies with size, although there is little scale economy above sizes of perhaps a few 100 kW (C2). Hydrogen plant costs for
Fig C-2. Operating voltages and current densities for various electrolyzers.

commercially available large scale alkaline electrolysis systems are currently about $500-600/kW, with projected costs as low as $300/kW (C3). Thomas and Kuhn have estimated recently that mass-produced small PEM electrolyzers might cost less than $300/kW H2 out (HHV) even at sizes of only a few kW (C4). High temperature electrolyzer costs are projected to be in the $750-1500/kW range.

The production cost of electrolytic hydrogen is strongly dependent on the cost of electricity. Electrolytic systems are generally competitive with steam reforming of natural gas only where low cost (1-2 cent/kWh) power is available, for example excess hydropower. Another niche market for electrolytic hydrogen may be remote sites, where conventional fuels are expensive due to high transport costs and wind power can be used to produce hydrogen (C5).

C.1. High Temperature Electrolysis Technology

If hydrogen is produced at a central electric power plant (for example from nuclear power), it may be advantageous to use a high temperature electrolyzer, which is integrated with the power plant. This allows use of high temperature heat available at the power plant to accomplish part of the water splitting, reducing the electrical input needed. The potential advantage is that less electrical power is needed to split water. The disadvantage is that high temperatures are needed, which requires more expensive materials.
Various types of high temperature electrolyzers have been developed, based on solid oxide electrolytes, as shown in Fig. C-3. Tubular and planar electrolysis cells have been constructed. Tubular solid oxide cells should have easier maintenance, as individual tubes could be readily accessed. Also, seals are easier at high temperature with tubular designs. Planar solid oxide systems are more compact, and have a higher power density (which could be advantageous for mobile applications).

A series of experiments were conducted on solid oxide electrolyzers in the 1970s and 1980s under the German HOT-ELLY program. Westinghouse has also developed tubular type solid oxide fuel cells, a technology that could be adapted for use in electrolyzers. Conceptual designs of high temperature electrolysis plants integrated with nuclear power plants or solar heat have been carried out.

Electrolyzers can operate over a range of current densities and voltages defined by a characteristic current-voltage (I-V) curve. The I-V curve for a high temperature electrolyzer is shown in Fig. C-4, as compared to a conventional electrolyzer. Depending on the operating point chosen, the high temperature electrolyzer operates in either “exothermic” mode, (where copious heat is produced by resistive losses in the cells, so that no external heat is needed) or “endothermic” mode, where external high temperature heat input is required, in addition to feed steam. The hydrogen production is proportional to the current density, so that higher current density (exothermic operations) means...
lower capital costs. However, the conversion efficiency is higher at low current density (endothermic operation). Exothermic operation has the added advantage that low temperature (150-200 C) steam feed is adequate, while endothermic operation requires 900 C input steam plus additional high temperature heat input. When heat is recovered from the power plant, the power plant output is decreased slightly, but this effect is less pronounced with exothermic operation. Overall, exothermic operation is economically preferable. Although the conversion efficiency is lower, this is balanced by lower capital costs, a simpler interface to the power plant, and better power plant efficiency.

A summary of operating conditions, performance, and costs is given in Table C.1 for conventional and high temperature electrolyzers.

Fig. C-4. The current-voltage (I-V) curve for a high temperature electrolyzer.
## Table C.1. Performance and Cost of Alternative Types of Electrolyzers

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<tr>
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<td>Electrical energy per Nm³ H₂</td>
<td>2.6 kWh&lt;sub&gt;e&lt;/sub&gt;</td>
<td>3.2 kWh&lt;sub&gt;e&lt;/sub&gt;</td>
<td>4.3 kWh&lt;sub&gt;e&lt;/sub&gt;</td>
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<td>Additional heat @ 950º C per Nm³ H₂</td>
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<td>Electrolyzer feed Steam per Nm³ H₂</td>
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<td>Current density</td>
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<td>0.6 A/cm²</td>
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<td>Op. voltage (V)</td>
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<td>Conv. eff. = HHV H₂/elec in</td>
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<td>Relative capital cost of plant (if 50% capital costs scale inversely with current density)</td>
<td>1.5 $1350/kWH&lt;sub&gt;2&lt;/sub&gt;</td>
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<td>0.67 $300-600/kWH&lt;sub&gt;2&lt;/sub&gt;</td>
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Appendix D. Cost and Economics of Hydrogen Production

D.1 Cost of Dedicated Hydrogen Production

The cost of fusion electricity is given by:

\[ P_{\text{fus}} = CRF_{\text{fus}} \times C_{\text{power}} / (8760 \text{ h/y} \times f_{\text{cap}}) + O&M_{\text{fus}} \]

where:
- \( P_{\text{fus}} \) = cost of fusion power ($/kWhe)
- \( CRF_{\text{fus}} \) = capital recovery factor for fusion plant = \( i / [1 - (1+i)^{-N_{\text{fus}}} ] \)
- \( C_{\text{power}} \) = capital cost of fusion power plant ($/kWе); function of plant size
- \( i \) = discount rate or internal rate of return
- \( N_{\text{fus}} \) = lifetime of fusion power plant (yrs)
- \( f_{\text{cap}} \) = power plant capacity factor
- \( O&M_{\text{fus}} \) = operation & maintenance of fusion power plant including utility costs for large power plant ($/kWhe)

The cost of hydrogen production is given by:

\[ P_{\text{H2}} = (CRF_{\text{electrol}} + O&M_{\text{electrol}}) \times C_{\text{electrol}} ($/kWHe)/(8760 \times f_{\text{cap}} \times 0.0036 \text{ GJ/kWh}) + \frac{P_{\text{fus}}}{n \times 0.0036 \text{ GJ/kWh}} \]

where:
- \( P_{\text{H2}} \) ($/GJ) = cost of hydrogen production (HHV)
- \( n \) = electrolyzer eff = H2 out (HHV)/elec in
- \( C_{\text{electrol}} \) = capital cost of electrolyzer ($/kWHe)
- \( O&M_{\text{electrol}} \) = electrolyzer O&M = fraction of electrolyzer cap. cost/y ($/y)
- \( CRF_{\text{electrol}} \) = capital recovery factor for electrolyzer = \( i / [1 - (1+i)^{-N_{\text{electrol}}} ] \)
- \( i \) = discount rate or internal rate of return
- \( N_{\text{electrol}} \) = lifetime of electrolyzer (yrs)

D.2. Economics of Electrolytic Hydrogen Production from Off-Peak Fusion Power

We derive the cost of electrolytic hydrogen produced from off-peak power as follows:

Define: \( f \) = the fraction of fusion power going to the electrolyzer during off-peak hours. Then \( (1-f) \) = the fraction of fusion power going to electricity production during off-peak hours.

- \( f = 0 \) = Electricity only
- \( f = 0.5 \) = 50% of power → H2 off-peak
- \( f = 1.0 \) = all power → H2 off-peak

Inputs defined:
- \( hon \) = # of on-peak hours per day
- \( hoff \) = # of off-peak hours per day = 24–hon
Peon = fusion power plant capacity during on-peak hours (kWe) [if high temperature electrolysis is used, there is no heat recovery for electrolyzer (kWe)]
Peoff = fusion power plant output during off-peak hours (kWe), for a conventional electrolyzer, “Peoff=Peon” = For a high temp electrolyzer, Peoff is a linear function of f (see Fig. 3).
n = electrolyzer eff = H₂ out (HHV)/elec in
Pelectrol = f n Peoff = electrolyzer H₂ output capacity (kWH₂ out HHV)
C_{power} = capital cost of fusion power plant w/no heat recovery ($/kWe); function of plant size
C_{electrol} = cap. cost of electrolyzer ($/kWH₂out)
O&M_{power} = O&M of fusion plant including utility costs ($/kWhe) = fraction of electrolyzer cap. cost/y ($/y)
O&M_{electrol}= electrolyzer O&M = fraction of electrolyzer cap. cost/y ($/y)
f_{cap} = power plant capacity factor
P_{fusAVE} = average cost of fusion power ($/kWhe)
P_{on} = cost of on-peak power ($/kWhe)
P_{off} = cost of off-peak power ($/kWhe)
P_{H₂} ($/GJ)= cost of hydrogen production (HHV)
i = discount rate or internal rate of return
N_{fus} = lifetime of fusion power plant (yrs)
CRF_{fus} = capital recovery factor for fusion plant = i/[1 -(1+i)^{-N_{fus}}]
N_{electrol} = lifetime of electrolyzer (yrs)
CRF_{electrol}= capital recovery factor for electrolyzer = i/[1 -(1+i)^{-N_{electrol}}]

It is assumed that the plant sells on-peak power for 5-8 cents/kWh (the range projected for future low or zero CO₂ generation options).

During the off-peak hours, the plant sells low cost electricity to an electrolysis plant. (If high temperature electrolysis is used, the fusion plant also provides heat to the electrolyzer.)

The cost of hydrogen is then estimated based on this off-peak power cost.

**First find the average cost of fusion power (including extra costs to the utility for large plants). This is given by:**

\[
P_{fusAVE} = \text{CRF}_{fus} \times \text{Peon} \times \text{C}_{power} / \{[\text{Peon} \times \text{hon}/24 + \text{Peoff} \times \text{hoff}/24] \times 8760 \text{ h/y} \times \text{fcap}\} + \text{O&M}_{power} + \text{Extra Utility Costs for Large Plant}
\]

It is assumed that the fusion plant sells on-peak electricity at Pon. Then the off-peak power cost Poff is

\[
f = 24/\text{hoff} \times P_{fusAVE}($/kWh) – \text{hon}/\text{hoff} \times \text{Pon}
\]

The cost of electrolytic hydrogen produced from off-peak power is then:

\[
P_{H₂} = (\text{CRF}_{electrol} + \text{O&M}_{electrol}) \times \text{Celectrol}/(\text{hoff}/24 \times 8760 \times \text{fcap} \times 0.0036 \text{ GJ/kWh}) + \text{Poff}/n /0.0036 \text{ GJ/kWh}
\]
Appendix E. References for Appendices


